Growth

Value

Performance

# Alberta Energy Company Ltd.

## 1998 Annual Report

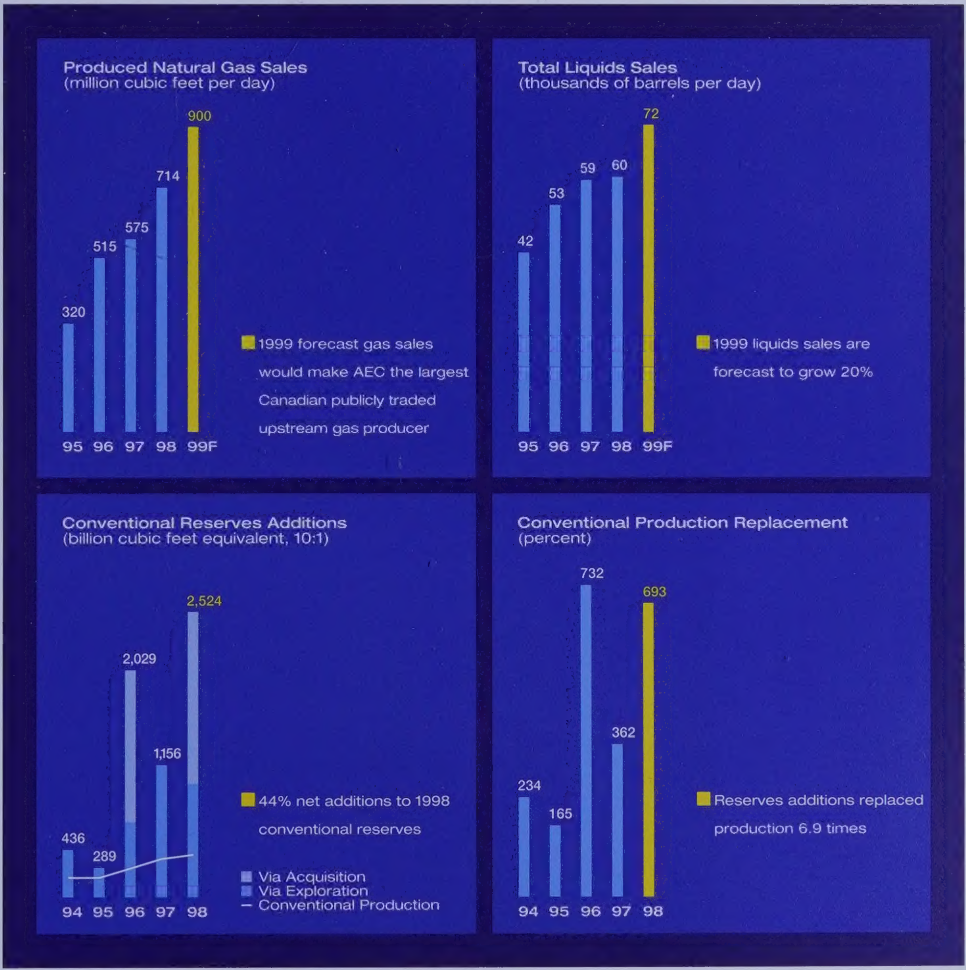
AEC

# Financial And Operating Highlights



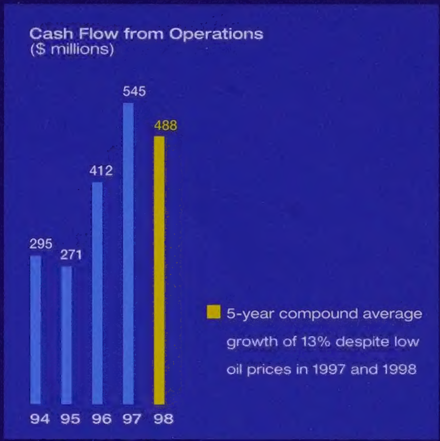
| **FINANCIAL** | **1998** | **1997** | **1996** |
|---|---|---|---|
| Cash Flow from Operations ($ millions) | 488.5 | 544.7 | 411.9 |
| $ per share - fully diluted | 4.06 | 4.67 | 3.82 |
| Net Earnings ($ millions, excluding 1997 dilution gain) | 24.4 | 21.7 | 68.0 |
| $ per share - fully diluted | 0.21 | 0.23 | 0.65 |
| Total Direct Capital Investment ($ millions) | 1,654.9 | 824.9 | 2,028.9 |
| Year-End Long-Term Direct Debt ($ millions) | 1,646.7 | 1,006.8 | 968.3 |
| Upstream Business Group | 1,355.4 | 519.4 | 367.0 |
| AEC Upstream | 887.4 | 519.4 | 367.0 |
| Amber Acquisition | 468.0 | – | – |
| Midstream Business Group | 291.3 | 487.4 | 601.3 |
| Debt-to-Capitalization Ratio - Corporate | 38:62 | 29:71 | 32:68 |
| Upstream Business Group | 36:64 | 20:80 | 16:84 |
| Midstream Business Group | 60:40 | 60:40 | 89:11 |
| Debt-to-Cash Flow - Upstream (times, excluding Amber) | 2.0 | 1.1 | 1.0 |
| **OPERATING** | | | |
| Produced Natural Gas Sales (million cubic feet/day) | 714 | 575 | 515 |
| Total Liquids Sales (barrels/day) | 60,074 | 58,940 | 53,155 |
| Conventional Oil and Natural Gas Liquids | 31,121 | 30,493 | 25,559 |
| Syncrude | 28,953 | 28,447 | 27,596 |
| Conventional Reserves Additions (billion cubic feet equivalent) | 2,524 | 1,156 | 2,029 |
| Conventional Production Replacement | 693% | 362% | 732% |

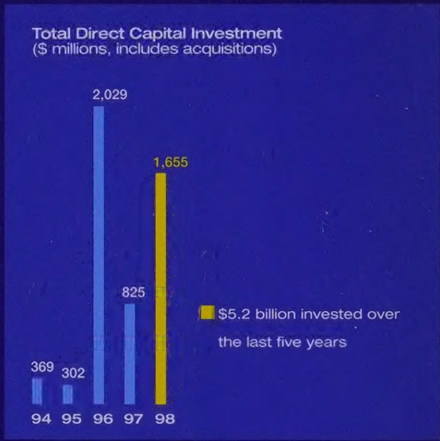
**Growth, Value, Performance. These words represent the essence of a business strategy which creates sustainable growth and builds underlying value. We've consistently demonstrated that this business strategy delivers performance for shareholders.**




**We are one of Canada's largest upstream (natural gas and oil exploration and production) companies with interests in midstream (natural gas storage, pipelines and natural gas liquids processing) assets which provide reliable cash flow and add value to our upstream business. With a current market capitalization exceeding Cdn $4 billion, we are an industry leader with:**

- 4.2 trillion cubic feet of natural gas reserves, the largest for a Canadian publicly traded producer
- 900 million cubic feet/day forecast 1999 produced natural gas sales, targeting to become the largest Canadian publicly traded producer
- 651 million barrels of liquids reserves, comprising 66% light and medium liquids
- 72,000 barrels/day forecast 1999 total liquids sales, of which 67% is light and medium liquids
- 7.1 million net acres of exploration land in North America and 1.8 million net acres outside North America
- midstream assets representing approximately 20% of AEC's asset base
- the largest independently owned natural gas storage facility in North America
- 70% ownership of AEC Pipelines, L.P., the largest intra-Alberta oil transporter

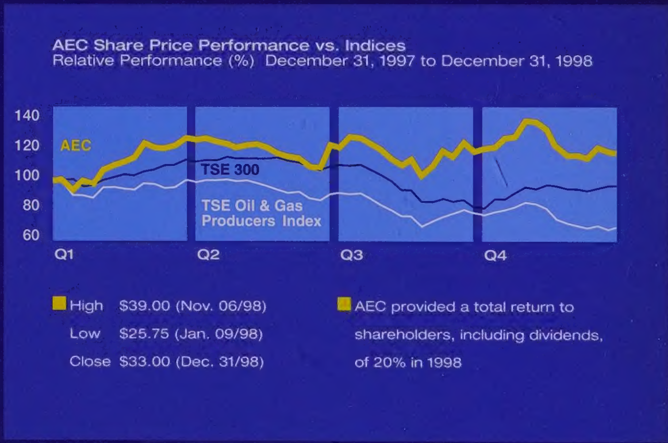



**"A" Credit Ratings**

**Low Upstream Debt-to-Cash Flow 2.0x**

(excludes Amber acquisition)




## Financial strength funds near-term and long-term growth

### Financial Strength to Fund Future Growth

AEC possesses a solid financial foundation with a low upstream debt-to-cash flow of 2.0x (excludes Amber-related debt of $468 million and two months' cash flow of $11 million), a low corporate debt-to-capitalization ratio of 38:62 and stable "A" and "A (low)" credit ratings. AEC has financial discipline and strives to maximize returns on invested capital over the entire commodity price cycle.

Midstream cash flow is largely independent of commodity prices and provides underlying financial strength.

### A Solid Reputation on North American Stock Markets

AEC is listed on the Toronto Stock Exchange (AEC), Montreal Exchange (AEC) and New York Stock Exchange (AOG), and is included in the S&P/TSE 60. The Company has the largest float (market capitalization freely available for trading) on the Toronto Stock Exchange Oil & Gas Producers Index. The stock traded an average 258,000 shares per day at an average value of $8.5 million per day in 1998. AEC is one of only three Canadian upstream producers that paid a dividend, $0.40 per share in 1998.

# How We Created Value and Growth in 1998

Produced natural gas sales grew by 24 percent

Added 2.5 trillion cubic feet equivalent of reserves through grassroots exploration and development and acquisition of Amber Energy Inc.

Increased total gas storage capacity to 110 billion cubic feet

Exploration success in Australia

### Achieved Production Objectives

AEC directed its 1998 capital programs at natural gas in anticipation of the new continental gas market and:

- increased produced natural gas sales by 24% to 714 million cubic feet/day
- increased productive field capacity and exited 1998 at 835 million cubic feet/day
- increased storage capacity by 29% to 110 billion cubic feet, with peak withdrawal capability of 1.9 billion cubic feet/day
- reduced oil development capital and maintained total liquids sales at 60,074 barrels/day due to depressed oil prices

### Created Value Through Acquisition of Amber Energy

AEC's pursuit of acquisitions has been guided by three fundamental criteria: value, strategic fit, and growth potential. In October 1998, stock market conditions and AEC's state of readiness combined to provide the opportunity for the acquisition of Amber Energy Inc.

Amber's principal assets were shallow gas and heavy oil, two areas of AEC expertise. The properties were at an early stage of development providing significant future growth potential. Amber's properties were large, concentrated land blocks with high working interests, contiguous to existing AEC properties.

### Achieved Exploration and Development Objectives

AEC continued its exploration momentum, achieved competitive costs and:

- added 989 billion cubic feet equivalent of conventional reserves by drilling 635 gross wells in western Canada
- achieved drillbit finding and development costs of $6.16/barrel of oil equivalent, in western Canada, proven plus probable
- realized exploration success in Australia
- made significant advancements in, and successfully tested steam-assisted gravity drainage (SAGD) technology at the Primrose pilot plant and identified enough resource to support future commercial production of 100,000 barrels/day

### Achieved Midstream Objectives

AEC strengthened its midstream operations in 1998 when it:

- increased operating cash flow to $114 million
- continued construction of the 14 billion cubic foot Wild Goose Gas Storage project in Northern California towards an April 1999 in-service date
- began preliminary engineering and design work for expansion of the Alberta Oil Sands Pipeline to 275,000 barrels/day to accommodate Syncrude growth, through AEC Pipelines, L.P.

## What Distinguishes Our Strategy


### A Strategy for Sustainable Growth

Growth, Value, Performance. These words represent the essence of a business strategy which creates sustainable growth and builds underlying value. We've consistently demonstrated that this business strategy delivers performance for shareholders. In striving to accomplish this, we:

- focus on
  - achieving a sustainable growth target of 10% with a stretch target of 15% in production, reserves, midstream returns and asset value
  - using capital efficiently by achieving low reserve replacement, operating and G&A costs
  - achieving top-quartile performance in our industries
- invest capital in the current depressed oil price environment that:
  - achieves the strongest natural gas production, reserves, storage, exploration land and transportation position in the industry
  - builds AEC's inventory of oil development projects for medium-term growth
- maintain financial strength, resilience and flexibility
- follow a disciplined, counter-cyclical strategy when seeking acquisitions that meet AEC's criteria of value, strategic fit and growth

# What Distinguishes Our Assets

**Canada's largest gas reserves: 4.2 trillion cubic feet**

**High-quality exploration prospects: 7.1 million net acres**

**North America's largest independent gas storage capacity: 110 billion cubic feet**

**25-year liquids production life: 651 million barrels**

### One of the Largest and Longest-Life Reserves Base

AEC has an exceptionally strong, long-life reserves base:

- 4.2 trillion cubic feet of natural gas with a reserve life index of 13 years
- 287 million barrels of conventional oil and natural gas liquids with a reserve life index of 20 years
- AEC's conventional reserves base is evaluated by McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd., well respected, independent engineers
- 364 million barrels of proven light sweet oil with a reserve life index of 32 years for proven Syncrude reserves. AEC is the second largest owner in the Syncrude project
- these figures exclude the potential for future commercial development of 350 million barrels of heavy oil at Primrose

### A Production Base Totaling 1.6 Billion Cubic Feet Equivalent/Day

AEC's forecast 1999 production base comprises 56% natural gas, 30% light liquids and 14% heavy oil.

### One of the Largest and Strongest Exploration Programs in the Canadian Oil and Gas Industry

AEC's exploration program provides a broad exposure to quality plays on shallow, intermediate and deep exploration prospects on 7.1 million net acres across the Western Canadian Sedimentary Basin and Northern U.S. The Company is the dominant operator in its core areas with highly concentrated working interests averaging 86%.

### Midstream Assets Providing a Stable Source of Operating Cash Flow

Pipelines, natural gas storage and natural gas liquids processing provide a reliable source of operating cash flow and add value to AEC's upstream business by enhancing market access.

| RESERVES REPLACEMENT COSTS, PROVEN AND PROBABLE RESERVES | | | | |
|---|---|---|---|---|
| **Canadian Conversion Standard – 10:1** | **1998** | **1997** | **1996** | **3-year Average** |
| **($ per barrel of oil equivalent)** | | | | |
| Drillbit Exploration and Development | 3.69 | 2.53 | 3.33 | 3.14 |
| Production Facilities Expansion | 1.89 | 1.67 | 1.79 | 1.77 |
| Minor Acquisitions | 0.19 | 0.07 | 0.29 | 0.17 |
| Exploration Land Growth | 0.39 | 1.54 | 1.10 | 1.03 |
| Drillbit Finding and Development Costs | 6.16 | 5.81 | 6.51 | 6.11 |
| Reserves Replacement Costs (including major acquisitions) | 5.49 | 5.81 | 6.90 | 6.06 |
| **International Conversion Standard – 6:1** | | | | |
| **($ per barrel of oil equivalent)** | | | | |
| Drillbit Exploration and Development | 2.63 | 1.67 | 2.27 | 2.14 |
| Production Facilities Expansion | 1.35 | 1.10 | 1.22 | 1.21 |
| Minor Acquisitions | 0.14 | 0.04 | 0.20 | 0.11 |
| Exploration Land Growth | 0.28 | 1.02 | 0.75 | 0.71 |
| Drillbit Finding and Development Costs | 4.40 | 3.83 | 4.44 | 4.17 |
| Reserves Replacement Costs (including major acquisitions) | 4.55 | 3.83 | 4.77 | 4.47 |

## Growing conventional reserves at competitive costs

### Total Production Replacement

AEC achieved 693% production replacement at a cost of $5.49/barrel of oil equivalent. AEC's conventional reserves additions were evaluated by McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd., well-respected independent engineers.

### Growth Through Exploration and Development

AEC's $610 million grassroots western Canadian conventional exploration and development program created value by:

- adding proven and probable reserves of 594 billion cubic feet of natural gas and 39.5 million barrels of liquids for a 272% production replacement
- achieving a proven and probable finding and development cost of $6.16/barrel of oil equivalent
- drilling 635 gross wells, including 207 exploration wells and 428 development wells with an overall success rate of 95%

### Growth Through Acquisition

AEC's $777 million acquisition of Amber's upstream assets created value by:

- adding proven and probable reserves of 204 billion cubic feet of natural gas and 135 million barrels of oil at a cost of $4.67/barrel of oil equivalent
- adding 871,000 net acres of highly prospective exploration land, independently evaluated at $50 million
- adding 100 million cubic feet/day of natural gas production and 12,000 barrels/day of oil production, with strong future growth potential

# How We Will Create Value and Growth in 1999 and Beyond

**Momentum**

**1994 - 1998**
Growth
5-Year Compound Average
- Production: 17%
- Reserves: 21%
- Midstream operating cash flow: 7%

**1999**
Growth
- Gas: 26%
- Liquids: 20%
- Storage capacity: 22%

**2000**
Growth
- Gas: 1 Bcf/day
- Liquids: huge upside
- Storage/Pipelines

## AEC has identified sustainable growth from existing assets through 2000

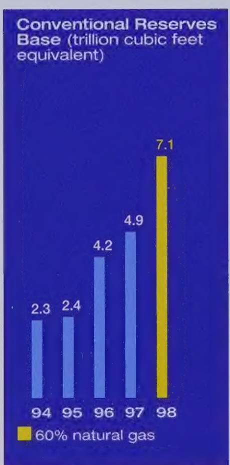
**In 1999, AEC plans to:**

- increase produced natural gas sales by 26% to 900 million cubic feet/day
- continue growing produced natural gas capacity toward being the first Canadian publicly traded producer to achieve average produced gas sales of 1 billion cubic feet/day in 2000
- increase liquids sales in 1999 by 20% to 72,000 barrels/day
- invest $510 million in grassroots exploration and development to increase conventional reserves and productive capacity
- drill up to 600 gross wells, 85% targeting natural gas
- continue advancements in SAGD technology through its pilot plant and reach a decision on the timing of the first 20,000 barrels/day commercial steam-assisted gravity drainage (SAGD) facility
- expand natural gas storage capacity by 22% to 134 billion cubic feet with peak withdrawal capability of 2.3 billion cubic feet/day
- sustain midstream operating cash flow at $115 million

# 1998 – A Year of Growth and Value Creation

**FELLOW SHAREHOLDERS:**

**The 1997 Annual Report presented your Company's progress toward our goal of being the leading senior producer in the Canadian oil and gas industry. In 1998, AEC emerged even more strongly as a frontrunner in creating growth in net asset value per share, production and share price. Growth, Value, Performance. These fundamentals are the key drivers behind the investment of shareholder capital at AEC. Creating underlying net asset value as a platform for sustainable growth generates investor confidence in our ability to return superior share price performance. AEC offers investors the attributes of both a growth company and a value-based company. This business strategy distinguishes AEC from its competitors, and, in 1998, it also distinguished AEC's share price performance from its competitors'. AEC's shareholders achieved a total return, including dividends, of 20% compared to a 30% decline in the Toronto Stock Exchange Oil and Gas Producers Total Return Index.**



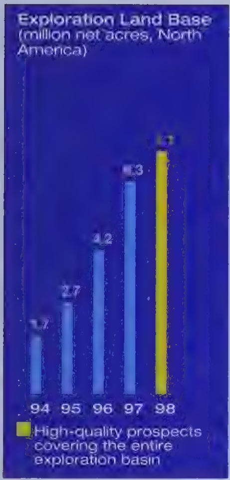

Key strategic objectives supporting AEC's Growth, Value, Performance business strategy include targeting annual sustainable growth rates of 10% with a stretch target of 15%. In 1998, we increased AEC's total production by 13%. Our production growth is backed by one of the industry's largest and longest life reserve positions. With 4.2 trillion cubic feet of natural gas reserves, AEC has the largest gas reserve base of any Canadian publicly traded upstream producer. AEC grew its combined conventional oil and Syncrude reserve life index to 25 years and added total conventional reserves of 2.5 trillion cubic feet equivalent, 6.9 times 1998 conventional production.

It is important for shareholders to note that AEC's conventional reserves are independently evaluated each year by McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd. – firms with a reputation for being realistic.

AEC's internal growth in the upstream group comes through building dominant positions in exploration land and production facilities. In 1998, AEC's North American exploration land base, the platform for one of Canada's largest and strongest exploration programs, expanded 12% to 7.1 million net acres and new production facilities expanded productive capacity by 26%. In addition, Syncrude ownership provided growing production at decreasing costs and increasing underlying value. In building an international upstream business unit as a platform for future production growth and value creation, AEC expanded its international exploration program beyond Argentina. The Company participated in a major natural gas discovery, the John Brookes-1 well, in Australia's Northwest Shelf. The AEC International business unit has now assembled a truly world-class team of experienced explorers.

Ownership of midstream assets provides a steady source of cash flow largely independent of commodity prices, while enhancing market access for AEC's upstream business units. In 1998, our midstream assets generated operating cash flow of $114 million, 19% of the Company's overall operating cash flow.

AEC has maintained a strong balance sheet, providing financial flexibility for counter-cyclical acquisitions which create value and future growth. In 1998, AEC acquired Amber Energy Inc., the Company's first significant corporate acquisition since the last industry downturn three years ago. Amber enhanced AEC's underlying value, and the strategic operating fit is excellent. Amber's production base of 100 million cubic feet per day of natural gas and 12,000 barrels per day of oil has substantial growth potential from its identified conventional reserves and potential application of enhanced recovery techniques. As well, Amber brought highly prospective exploration opportunities to AEC.




## 1998 OPERATING PERFORMANCE

AEC's 1998 business plan focused on strengthening natural gas reserves, production and storage capacity, while positioning AEC for strong future growth in liquids production during a period of counter-cyclical opportunity. AEC's people delivered the following key results in 1998:

- increased total conventional reserves by 2.5 trillion cubic feet equivalent at a reserves replacement cost of $5.49 per barrel of oil equivalent
- increased natural gas reserves to 4.2 trillion cubic feet, the largest among Canadian publicly traded companies
- increased natural gas sales 24% to 714 million cubic feet per day, exceeding the target of 700 million cubic feet per day set in last year's Annual Report
- increased the number of gross wells drilled by 32% to 645 with an average success rate of 95%
- added reserves through the drillbit of nearly 1 trillion cubic feet equivalent
- matched the very strong 1997 drillbit finding and development cost performance
- decreased upstream general and administrative costs by a further 7% to $0.51 per barrel of oil equivalent, one of the lowest in the industry
- strengthened Canadian gas storage capacity, and continued construction of the Wild Goose Gas Storage facility, California's first independent natural gas storage and trading hub
- continued to exceed expectations for well productivity and cost at the Primrose steam-assisted gravity drainage (SAGD) project

**In 1998, AEC emerged even more strongly as a frontrunner in creating growth in net asset value per share, production and share price.**

## FINANCIAL RESULTS

Higher natural gas sales, stable gas prices and steady, reliable cash flow from midstream operations largely offset the severe impacts of plunging oil prices on the Company's financial results for 1998.

Cash Flow from Operations decreased 10% to $488.5 million ($4.06 per share, fully diluted) due principally to a 29% decrease in AEC's average liquids price. Consolidated Net Earnings for 1998 were $24.4 million, compared with $21.7 million in 1997, excluding the 1997 dilution gain resulting from the creation of AEC Pipelines, L.P.

AEC's six entrepreneurial business units are organized into two business groups: upstream (oil and gas exploration, production and marketing) and midstream (pipelines, natural gas liquids processing and natural gas storage and hub services). These two groups have separate capital structures based on industry norms.

After a $1.7 billion capital program and a year of very weak oil prices, AEC's key financial measures remain strong with upstream debt-to-cash flow of 2.0 times, on a trailing basis. This ratio excludes the cash flow and debt that the Company assumed as a result of the Amber acquisition late in 1998. The debt-to-capitalization ratios were healthy at 36:64 for upstream, and 38:62 on a corporate basis.

In conjunction with the $777 million acquisition of Amber Energy's upstream assets, AEC received a great vote of confidence from shareholders, raising $345 million in common equity. The balance of the Amber acquisition cost was financed through bank debt and Medium Term Notes. After the Amber transaction, AEC has $1.1 billion of unused credit lines.

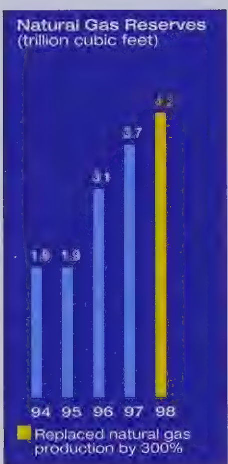
Both bond rating agencies in Canada reviewed AEC as a result of the Amber transaction with very good results. For our long-term debt, the Canadian Bond Rating Service has reaffirmed our "A" rating and Dominion Bond Rating Service has given AEC an "A low", both with a stable outlook. For our commercial paper, both agencies have reaffirmed our ratings of "A-1" and "R-1 (low)" with a stable outlook.

### CHALLENGES ENCOUNTERED IN 1998

AEC's accomplishments were tempered by a number of challenges in 1998:

- A 29% decrease in AEC's average liquids price, driven by the lowest world oil prices in 21 years, led to a decision to reduce oil development expenditures by $40 million. This resulted in our liquids production being 95% of the target of 63,000 barrels per day set in last year's Annual Report.
- Natural gas unit operating costs increased 5%, due partly to unreliable electric power service at major gas plants and other unforeseen operating outages.
- AEC Pipelines, L.P. continued to experience throughput restrictions due to delays in upgrades required on the Platte Pipeline in the United States.
- Along with other oil and gas operators in northwestern Alberta, AEC experienced acts of industrial sabotage at natural gas production facilities. This resulted in increased security costs and considerable stress among employees and community residents. AEC is committed to the safety, health and well-being of our people, and their neighbours and continues to work on resolving this issue in cooperation with the community and law enforcement authorities.

**AEC's 1998 business plan focused on strengthening natural gas reserves, production and storage capacity, while positioning AEC for strong future growth in liquids production during a period of counter-cyclical opportunity.**



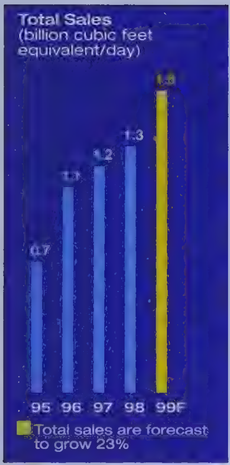

### AEC'S PLAN FOR 1999 AND BEYOND

AEC's 1999 direct core capital program of $750 million will be primarily focused on further strengthening our dominant position in natural gas. Our ability to respond aggressively to future oil price increases through inventoried production growth capability will also be further strengthened. We are targeting a 23% increase in our overall production base. In addition, the search for acquisitions which meet our criteria of value, strategic fit and growth will continue, both domestically and internationally, during this period of exceptional counter-cyclical opportunity.

AEC's 1999 operating plan contains the following key objectives:

- Target produced natural gas sales to increase by 26% to 900 million cubic feet per day. AEC holds the largest Canadian natural gas reserves position and plans to become the largest gas producer among publicly traded Canadian companies. Growing field production capacity, combined with our natural gas storage position, will result in gas sales exceeding 1 billion cubic feet per day during periods of market strength. The Company's strong position in natural gas is the culmination of a five-year plan to be the company most able to respond to historic changes in natural gas markets, resulting from completion of major new export pipelines to the United States.
- Target liquids production for 1999 at 72,000 barrels per day, a 20% increase. In 1998, AEC elected to defer oil development programs and will continue to do so in 1999.

Looking beyond 1999, currently identified natural gas growth opportunities should allow the Company to achieve gas sales of approximately 1 billion cubic feet per day in 2000. Predicting year-2000 oil volumes is more problematic because of the numerous worldwide factors impacting oil prices. The Company is assuming world oil prices will remain depressed; our business plan is based on US$12 WTI (West Texas Intermediate) for the remainder of 1999. As a result, AEC will defer $100 million of oil development projects representing 15,000 barrels per day of future growth in oil production. When world oil prices appear sustainable at a US$15 WTI level or higher, AEC will be in a position to develop these inventoried oil projects and increase its liquids production beyond 85,000 barrels per day. In the longer term, further growth will come from our huge Primrose heavy oil holdings.




**INDUSTRY CONDITIONS**

The mild El Niño weather of 1998 resulted in record year-end natural gas storage levels. The winter of 1999 has also been mild, and storage drawdowns have not been as substantial as expected. Given the mild winter weather experienced to the date of publishing this report, the strongest gas markets and prices may, in fact, occur during the second half of 1999. Despite these factors, AEC expects 1999 gas prices to be higher than in 1998 and the outlook for gas prices beyond 1999 is for further strengthening.

AEC is basing its 1999 plans on a continuation of very low oil prices; however, like all commodity price cycles, the price of oil will not remain at the current depressed levels. Periods of low commodity prices, over time, lead to growth in consumption and weakening of production. Most of AEC's competitors are hampered by reduced cash flow and very limited access to financial markets. This will no doubt lead to further asset sales and corporate consolidation. AEC is well positioned with growing revenues from natural gas sales, midstream investments and a strong balance sheet. AEC's objective is to emerge from this time of industry turmoil even stronger than when we entered.

**THE PEOPLE BUILDING AEC**

This Annual Report sets out the performance and goals of AEC's four upstream and two midstream business units. AEC operates in a decentralized manner with semi-autonomous entrepreneurial business units, each accountable for creating value from the shareholders' assets and capital entrusted to them. Supporting these business units is a small, efficient corporate head office dedicated to helping the business units achieve success. The talented, dedicated people throughout our business units and corporate groups have placed AEC among the highest performing companies. AEC's people value our Company's reputation for a high level of integrity, and for being a special place to work. At AEC, we share a passion for who we are and what we do.

As AEC grows, so does our employee base. We are pleased to welcome a very capable group of new employees from Amber Energy, and elsewhere, who will add value to our Company.

The AEC story is one that people throughout the Company believe in strongly and they have a large personal stake. At year-end 1998, Directors, Management and employees held shares and options totaling 8% of our fully diluted market value of $4.4 billion.

**The talented, dedicated people throughout our business units and corporate groups have placed AEC among the highest performing companies.**

Our April 1999 Annual Meeting will mark the end of an era for AEC. Two founding Directors, each having served since 1975, will reach compulsory retirement age. Matt Baldwin has contributed much to AEC over all of those years and the quality of his advice, his level of enthusiasm and his pride in being associated with AEC remained strong over the entire period. Dave Mitchell was AEC's founding President and CEO until the end of 1993, and since that time, has served as non-executive Chairman. Dave's legacy as a respected business and community leader, his tremendous pride in the development, growth and success of those who worked with him and the strength of the assets which were built during his tenure as CEO, combined with his absolute integrity, are all important reasons for the strength of today's Alberta Energy Company.

On behalf of the Board of Directors, the Management team and everyone at AEC, we wish Matt and Dave a long, healthy and happy retirement.

Stan Milner, another founding Director of AEC, has accepted the Board's nomination for the position of non-executive Chairman, to succeed Dave Mitchell following the 1999 Annual Meeting. As well, Ian Delaney, non-executive Chairman of Sherritt International Corporation, has agreed to allow his name to stand for election to the Board at the Annual Meeting on April 21, 1999.

**Gwyn Morgan**
*President and Chief Executive Officer*
*February 17, 1999*


**AEC's** strategy is to be the most dominant company in our operating areas. Our asset base is characterized by large, concentrated land holdings, high ownership interests and control of producing facilities.

## Entrepreneurial Business Unit Structure


AEC operates in a decentralized manner with six semi-autonomous, entrepreneurial business units. Four upstream business units focus on exploration and production and two midstream business units provide reliable cash flow through gas storage, pipeline transportation and natural gas liquids processing. Each unit is accountable for creating value from the shareholders' assets and capital entrusted to it.

# AEC East

Upstream

**The AEC East business unit is comparable in size to many of Canada's senior oil and natural gas producers. It focuses on shallow gas and oil exploration and development in the plains areas of the Western Canadian Sedimentary Basin. AEC East has achieved regional domination through large consolidated land positions.**

### STRATEGY

- pursue production and reserves growth targets through low-risk exploration and development of sweet, dry, shallow gas; light and heavy oil
- pursue medium-risk exploration to broaden base for continued growth
- pursue select, value-added acquisitions
- maintain advantages of high working interests, low operating costs, low royalties and well-developed infrastructures
- be the industry's lowest-cost heavy oil producer
- develop and implement innovative low-cost recovery technologies
- position AEC to implement a commercial-scale steam-assisted gravity drainage (SAGD) project when economic conditions are appropriate

### KEY ASSETS

- 1.9 trillion cubic feet of proven and probable shallow natural gas reserves
- 230 million barrels of proven and probable conventional oil reserves
- 3.5 million net acres of exploration land
- 94% ownership of petroleum and natural gas rights on the 1,000-square mile Suffield Range and 97% on the 2,000-square mile Primrose Range
- more than 4,500 producing wells
- over 85% average working interest
- 530 million cubic feet/day of low royalty, low operating cost natural gas production
- 22,000 barrels/day of low royalty, low operating cost heavy oil production
- 6,000 barrels/day of conventional light oil production
- 28 billion barrels of heavy oil resource in Primrose
- 25-billion cubic foot Primrose Gas Storage facility
- 200 million cubic feet/day Suffield Gas Pipeline

### POTENTIAL GROWTH

- significant additional exploitation potential on existing land bases at Suffield, Primrose and Pelican Lake
- exploration and development potential on recently acquired land in the Pelican Lake and Springburn areas in Alberta, Wymark area in Saskatchewan, Ekwan/Sierra area in British Columbia
- commercial application of SAGD technology leading to production of 20,000 barrels/day of oil in 2001
- enough resource has been delineated in the vicinity of the Primrose Range heavy oil pilot to support future commercial production of 100,000 barrels/day

## Achieved record production of 574 million cubic feet equivalent/day in 1998

### OPERATIONS SUMMARY

| | 99F | 98 | 97 | 96 |
|---|---|---|---|---|
| Production | | | | |
| natural gas (million cubic feet/day) | 530 | 408 | 325 | 276 |
| conventional oil (barrels/day) | 28,000 | 16,575 | 17,389 | 12,742 |
| Proven and Probable Reserves | | | | |
| natural gas (billion cubic feet) | N/A | 1,859 | 1,543 | 1,457 |
| conventional oil (million barrels) | N/A | 230.1 | 65.8 | 50.4 |
| Capital Expenditures ($ millions) | 330 | 237 | 238 | 185 |
| Gross Wells | | | | |
| exploration | 100 | 77 | 55 | 81 |
| development | 400 | 351 | 209 | 251 |
| Undeveloped Lands (thousands of net acres) | N/A | 3,506 | 2,562 | 2,245 |

## 1998 OBJECTIVES VS. PERFORMANCE

| Objectives | Performance |
|---|---|
| □ replace production by 170% | □ achieved over 300% production replacement through exploration and development, or 1,000% including the Amber acquisition |
| □ increase natural gas production by 20% to 389 million cubic feet/day | □ surpassed target and achieved record natural gas production of 408 million cubic feet/day, an increase of 26%<br>□ exited the year at 510 million cubic feet/day, including 100 million cubic feet/day from Amber properties |
| □ maintain heavy oil production at 1997 levels and defer production increases until prices improve | □ development of heavy oil was deferred due to low oil prices<br>□ exited the year at 26,000 barrels/day, including 12,000 barrels/day from Amber properties |
| □ develop a 25-billion cubic foot proprietary natural gas storage project at Primrose | □ successfully completed project in four months from concept to first injection in April 1998 |
| □ complete construction of Suffield Gas Pipeline project to reduce transportation costs | □ constructed Suffield Gas Pipeline on budget and began transporting gas in November 1998<br>□ currently transporting 150 million cubic feet/day |
| □ initiate plans for a potential 500-well recompletion program in 1999 and a 500-well drilling program for Suffield shallow gas | □ advanced program forward into 1998 and successfully performed a 560-well recompletion program and drilled 285 new shallow gas wells |
| □ initiate enhanced oil recovery techniques to realize full potential of Suffield heavy oil pools | □ granted enhanced oil recovery status by regulatory authorities for all major oil pools in Suffield<br>□ initiated evaluation of enhanced recovery techniques |
| □ drill horizontal wells and install production facilities for initial production at Pelican Lake | □ drilled eight horizontal wells and installed a 5,000-barrel/day oil battery |
| □ complete business transactions to facilitate exploration on lands in the Williston Basin at Fort Berthold, North Dakota | □ focused on other opportunities within the Williston Basin due to delays in finalizing the Fort Berthold agreement |
| □ complete SAGD commercial evaluation; determine heavy oil marketing strategy | □ achieved industry-leading advancements and success with SAGD technology at Primrose<br>□ demonstrated feasibility and commenced commercial project design |

## 1999 OBJECTIVES

- □ increase natural gas production 30% to 530 million cubic feet/day
- □ increase liquids production 69% to 28,000 barrels/day
- □ inventory 12,000 barrels/day of heavy oil development due to depressed oil prices
- □ maintain operating costs at below $0.35/thousand cubic feet of natural gas production
- □ reduce operating costs to $4.50/barrel for liquids
- □ advance design and construction plans for the 20,000 barrels/day Primrose SAGD commercial project
- □ optimize the combined assets of AEC and Amber through the implementation of a sound development plan
- □ develop a by-pass pipeline for Primrose natural gas
- □ expand exploration to provide opportunities for sustained growth

## AEC West

Upstream

**AEC West is one of the largest and strongest exploration and production companies in its operating region. It is the dominant natural gas producer in the West Peace River Arch, controlling 80% of the leased acreage. This upstream business unit primarily targets multi-zone, liquids-rich, deep gas in lands along the eastern slopes of the foothills in northeastern British Columbia and western Alberta.**

### STRATEGY

- continue exploration and development of properties in the West Peace River Arch, Edson region and northeast British Columbia
- target multi-zone, liquids-rich gas prospects along the eastern slopes of the Rocky Mountain foothills
- develop a portfolio of high-potential new concept exploration prospects through New Ventures group
- pursue select value-added acquisitions

### KEY ASSETS

- 2.3 trillion cubic feet of proven and probable natural gas reserves
- 51 million barrels of light liquids reserves
- 3.6 million net acres of exploration land
- one of the largest exploration landholders in British Columbia
- multi-zone rights on large contiguous plays
- control of the Sexsmith and Hythe plants, the two largest sour gas processing plants in the West Peace River Arch
  - 400 million cubic feet/day gross sales capacity (63% AEC)
  - 100% ownership of a 150-mile gas gathering infrastructure
- 70 million cubic feet/day Maxhamish gas plant and associated gathering system
- Tupper Pipeline which ties AEC reserves in Tupper/Doe area of British Columbia to AEC's Hythe plant in Alberta

### POTENTIAL GROWTH

- dominant position in West Peace River Arch, controlling 80% of acreage in AEC operating areas
- solid land base to continue exploration concepts into British Columbia
- deep basin, high-potential exploration at Edson
- New Ventures group to develop prospects outside of core focus areas

## Achieved record production of 423 million cubic feet equivalent/day in 1998

### OPERATIONS SUMMARY

| | 99F | 98 | 97 | 96 |
|---|---|---|---|---|
| Production | | | | |
| natural gas (million cubic feet/day) | 350 | 300 | 263 | 229 |
| liquids (barrels/day) | 11,000 | 12,329 | 11,421 | 11,576 |
| Proven and Probable Reserves | | | | |
| natural gas (billion cubic feet) | N/A | 2,348 | 2,142 | 1,603 |
| oil and natural gas liquids (million barrels) | N/A | 51.2 | 51.7 | 59.4 |
| Capital Expenditures ($ millions) | 180 | 390 | 441 | 263 |
| Gross Wells | | | | |
| exploration | 60 | 130 | 90 | 62 |
| development | 25 | 77 | 123 | 65 |
| Undeveloped Lands (thousands of net acres) | N/A | 3,584 | 3,694 | 2,034 |

## 1998 OBJECTIVES VS. PERFORMANCE

| Objectives | Performance |
| --- | --- |
| □ increase natural gas production to 330 million cubic feet/day | □ achieved record natural gas production of 300 million cubic feet/day, an increase of 14%<br>□ exited the year at 325 million cubic feet/day |
| □ replace 1998 production by 250% | □ added net 357 billion cubic feet equivalent in reserves, replacing production by 230% |
| □ continue to acquire and develop strategic British Columbia lands and reserves and add new production to the Hythe plant | □ drilled seven wells in new exploration concepts<br>□ added 8 million cubic feet/day of new production to the Hythe plant through the Tupper Pipeline |
| □ continue aggressive exploration and development program in the West Peace River Arch area and fill unused plant capacity | □ developed and added 22 million cubic feet/day of new production |
| □ test key, high-potential prospects in the Edson/ANG Pipeline Corridor area | □ successfully tested three high-impact, deep exploration plays<br>□ Berland River well drilled in August, onstream in November at 26 million cubic feet/day (50% AEC)<br>□ expect 15 million cubic feet/day sustained production at Smoky well (65% AEC) |
| □ develop high-potential prospects in New Ventures and test a minimum of four new concepts in Wyoming, Alberta and northeast British Columbia | □ drilled four new concepts, one of which tested gas<br>□ assembled land and acquired seismic on three prospects in Wyoming which will be drilled in 1999<br>□ negotiated agreements with Aboriginal groups in central Northwest Territories which will allow for seismic acquisition in 1999 and drilling in 2000 |
| □ complete northwest gas expansion to 25 million cubic feet/day and continue regional prospect development | □ expanded northwest gas production to 21 million cubic feet/day and identified additional drilling locations |
| □ develop Maxhamish gas project in 1998 and begin commercial production in the second quarter of 1999 | □ commenced construction on a plant with a capacity of 70 million cubic feet/day and associated gathering system and sales pipeline<br>□ currently on schedule for April 1999 start-up |

## 1999 OBJECTIVES

- □ increase natural gas production 17% to 350 million cubic feet/day
- □ target liquids production of 11,000 barrels/day
- □ complete construction and commission gathering system, plant and gas sales pipeline at Maxhamish by April 1999
- □ inventory 1,500 barrels/day of oil development projects due to low oil prices
- □ evaluate and test high potential prospects in the Edson deep basin region
- □ replace production by 180%

# AEC International

Upstream

**A compact, world-class team is applying AEC's strategy of growth, value and performance to international exploration. Our goal is to develop a substantial international business unit comparable in size to one of AEC's domestic upstream business units.**

### STRATEGY

- build a substantial, profitable reserves and production base by 2002
  - target production of 25,000 to 30,000 barrels of oil equivalent/day through exploration and exploitation in Australia, Latin America and Middle East/North Africa
- acquire high working interests in low-to-medium risk plays
- focus resources on four to six carefully screened and highly prospective basins and plays in a select number of countries
- invest approximately 10-15% of the Company's core capital budget
- drill six to eight net exploration wells in high-quality prospects in 1999
- make strategic acquisitions in focus basins

### KEY ASSETS

- 1.8 million acres of exploration lands in large blocks in Australia and Argentina
- new and emerging exploration plays on existing lands
- strong team with proven leadership in international exploration and more than an average of 10 years international experience per person

### POTENTIAL GROWTH

- appraisal and development of major gas/condensate discovery in Carnarvon Basin, Northwest Shelf of Australia
- participation in drilling the potential high-reward Alov prospect in Azerbaijan
- large prospective land positions
  - Neuquen Basin of Argentina
  - two basins on the Northwest Shelf of Australia
- New Ventures team seeking high-quality exploration and acquisition opportunities

## Focus on a small number of low-to-medium risk, high-reward basins in select countries

### OPERATIONS SUMMARY

| | 99F | 98 | 97 | 96 |
|---|---|---|---|---|
| Production | | | | |
| conventional oil (barrels/day) | 2,000 | 2,217 | 1,683 | 1,241 |
| Proven and Probable Reserves | | | | |
| conventional oil (million barrels) | N/A | 5.2 | 4.2 | 3.3 |
| Capital Expenditures ($ millions) | 100 | 65 | 48 | 25 |
| Gross Wells | | | | |
| exploration | 10 | 5 | 4 | 1 |
| development | 5 | 5 | 7 | 5 |
| Undeveloped Lands (thousands of net acres) | N/A | 1,751 | 2,945 | 2,711 |

## 1998 OBJECTIVES VS. PERFORMANCE

| | Objectives | Performance |
|---|---|---|
| **Argentina** | □ evaluate and capture potential exploration upside by drilling exploration wells on existing and newly acquired lands in the Neuquen Basin | □ deferred exploration program on new lands pending finalization of land tenure by government; drilled and abandoned two exploration wells on existing lands |
| | □ shoot 500 square kilometres of 3-D seismic in Rio Negro area on existing and newly acquired lands, building AEC's exploration drilling inventory for future growth | □ shot 450 square kilometres of high-quality 3-D seismic and developed prospect inventory for 1999 drilling |
| | □ test new play type in the Estancia Vieja area | □ successfully tested four wells in the Pre-Cuyo play in Puesto Prado |
| | □ drill six development wells, complete surface facilities and implement a waterflood program in the Puesto Prado pool | □ drilled five development wells and commenced waterflood in the fourth quarter |
| | □ shoot seismic and prepare a drilling location at Acambuco | □ withdrew from block based on new land survey |
| **Australia** | □ build expertise and prospect inventory | □ established an experienced team to aggressively explore proven basins on the Northwest Shelf |
| | □ accelerate opportunity through appropriate farm-ins, bid round participation and acquisitions | □ farmed-in on two blocks; awarded two blocks in bid round |
| | □ pursue plays in the Carnarvon, Canning and Bonaparte basins on the Northwest Shelf | □ drilled one gas/condensate discovery, John Brookes-1 (25% working interest), which flowed 53 million cubic feet/day of natural gas with 460 barrels/day of condensate<br>□ drilled and abandoned two other offshore wells |
| **Thailand** | □ complete seismic program and interpretation<br>□ farm-out a 50% working interest in lands in the northern basin area and "spud" a test well if required | □ completed work program and elected to discontinue operations |
| **North Africa/Middle East /Caspian Sea** | □ organize a New Ventures team to expand into the region by third quarter of 1998 | □ established experienced New Ventures team<br>□ currently pursuing opportunities in North Africa, the Middle East and the Caspian Sea |
| | □ evaluate and capture appropriate opportunities in North Africa and the Middle East | □ negotiated a 5% interest in an agreement to test the Alov prospect, the largest known geologic structure in Azerbaijan |

## 1999 OBJECTIVES

**Argentina**
- □ appraise and develop existing discoveries at Puesto Prado, Ojo de Agua and Puesto Flores Oueste
- □ conduct an exploration drilling program on existing acreage
- □ build prospect inventory to access gas potential in western Neuquen Basin
- □ exit 1999 with 4,000 barrels/day of production
- □ reduce operating costs to less than US$3.00/barrel by the end of 1999

**Australia**
- □ appraise and initiate a development plan for the John Brookes-1 discovery
- □ identify and capture farm-in opportunities to build on success at John Brookes in the Carnarvon Basin
- □ plan to evaluate and drill prospects in the Carnarvon Basin

**North Africa/Middle East /Caspian Sea**
- □ evaluate and identify areas with superior reserves potential
- □ establish a presence in at least one new core area
- □ complete seismic program in Azerbaijan and commence drilling first exploration well

# AEC Syncrude

Upstream

**AEC Syncrude is the second-largest owner in the Syncrude Project, which is the single largest source of oil production in Canada, and the world's largest producer of oil sands-based light, sweet oil. Constantly improving technologies, combined with extremely large, long life reserves provide sustainable production and value growth for this upstream business unit.**

### STRATEGY

- accelerate plant expansion and develop high-quality bitumen resources
- develop and employ new technologies to increase efficiencies leading to lower costs
- double production by 2007
- reduce operating costs to $12.00/barrel by 2000

### KEY ASSETS

- ownership interests
  - 13.75% joint venture interest
  - 5.0% gross overriding royalty on an additional 6.25%
- 364 million barrels of proven reserves net to AEC
- 28,953 barrels/day of light, sweet oil priced at $0.80 premium to light oil at Edmonton
- no exploration risk
- non-declining production base
- large, integrated infrastructure including upgraders and extraction equipment

### POTENTIAL GROWTH

- production is targeted to increase by 35% to 39,000 barrels/day in five years and to double by 2007
- proven and probable reserves can sustain production at the expanded rate until the year 2041
- minimal Crown royalty in the next six years

## Syncrude produced its billionth barrel in 1998

### OPERATIONS SUMMARY

| | 99F | 98 | 97 | 96 |
|---|---|---|---|---|
| Sales (barrels/day) | 31,000 | 28,953 | 28,447 | 27,596 |
| Proven Reserves (million barrels) | N/A | 364 | 381 | 269 |
| Probable Reserves (million barrels) | N/A | 355 | 347 | 490 |
| Proven Reserve Life Index (years) | N/A | 32 | 37 | 27 |
| Capital Expenditures ($ millions) | 90 | 68 | 49 | 29 |

## 1998 OBJECTIVES VS. PERFORMANCE

| Objectives | Performance |
|---|---|
| □ increase production to 30,000 barrels/day | □ achieved production of 28,953 barrels/day, an increase of 506 barrels/day and a new record for average daily production<br>□ produced the 1 billionth barrel of oil since start-up<br>□ maintained expansion momentum despite low oil price environment |
| □ reduce operating costs from $13.78 to $13.60/barrel | □ reduced operating costs to $13.55/barrel |
| □ file upgrading expansion application with the AEUB | □ filed application in June 1998 |
| □ acquire additional oil sands leases | □ acquired two high-quality leases within 15 kilometres of existing upgraders |

## 1999 OBJECTIVES

- □ increase production by 7% to 31,000 barrels/day
- □ reduce operating costs to $12.40/barrel
- □ maintain Syncrude expansion momentum by completing the first phase of expansion engineering design
- □ obtain AEUB approval for upgrader expansion

# AEC Storage and Hub Services

Midstream

**The operator of AECO, North America's largest independent natural gas storage and trading facility, AEC Storage and Hub Services is one of the Company's two midstream business units. In addition to providing reliable cash flow from storage services, gas storage allows AEC's upstream business units to optimize field facility development capital and capture seasonal peaks in gas prices.**

### STRATEGY

- maintain leadership in gas storage through innovative, market-responsive customer service and cost-effective operations
- capture new investment opportunities using strong technical and commercial expertise
- optimize asset utilization

### KEY ASSETS

- 85-billion cubic foot AECO gas storage reservoir in Alberta
  - largest independent facility in North America
  - Canadian industry pricing point for gas trading
  - 1.8 billion cubic feet/day peak withdrawal capacity
- 14-billion cubic foot Wild Goose Gas Storage reservoir in California
  - first independent facility in the State
  - 200 million cubic feet/day peak withdrawal capacity
- contracts with terms varying from one to 15 years

### POTENTIAL GROWTH

- expansion of Alberta capacity
- expansion potential of Wild Goose facility as market conditions develop
- new investment opportunities through continued restructuring of North American natural gas industry

### 1998 OBJECTIVES VS. PERFORMANCE

| Objectives | Performance |
| --- | --- |
| □ increase operating cash flow by 15% | □ increased operating cash flow 77% through new contracts and asset optimization |
| □ increase capacity at AECO to service new contracts | □ enhanced deliverability to serve new contracts<br>□ AECO capacity fully contracted |
| □ commence construction of the Wild Goose facility towards a 1999 start-up | □ on schedule for April 1999 start-up |
| □ acquire new pool capacity in Alberta for expansion of 10 billion cubic feet | □ announced plans for 1999 development of new gas storage capacity in northwest Alberta |
| □ introduce stronger risk optimization tools | □ implemented with positive impact on operating cash flow |

### 1999 OBJECTIVES

- increase operating cash flow by 30% to $30 million
- commission the Wild Goose Gas Storage facility in April 1999
- complete 10-billion cubic foot gas storage facility in northwest Alberta
- continue aggressive growth strategy leading to new facility investment

Midstream

**AEC Pipelines & Gas Processing is Alberta's largest intra-provincial oil transporter and owns natural gas liquids extraction assets. Its principal asset is AEC's 70% ownership of the AEC Pipelines, L.P., which generates a reliable source of cash flow from long-term contracts.**

### STRATEGY

- pursue growth through pipeline transportation investments in North America and other regions
- anticipate and capture emerging market opportunities through creative entrepreneurial business agreements
- focus on customers
- leverage existing asset base and technical expertise to capture new investment opportunities
- apply the best available commercial technology

### KEY ASSETS

- 70% ownership in AEC Pipelines, L.P. (TSE-listed ALB.UN), which has:
  - 100% interest in Cold Lake Pipeline System
  - 100% interest in Alberta Oil Sands Pipeline System
  - indirect 50% ownership in Express Pipeline System
  - long-term shipper contracts
- 35% interest in the Empress Straddle Plant
- 33% interest in Alberta Ethane Gathering System

### POTENTIAL GROWTH

- Alberta Oil Sands Pipeline and Cold Lake Pipeline strategically positioned to transport increasing Alberta synthetic and heavy oil production
- increasing throughputs on the Express Pipeline system to serve U.S. Midwest and Rocky Mountain region markets
- capability to expand Express Pipeline from 172,000 to 280,000 barrels/day at very low capital cost
- international opportunities

### 1998 OBJECTIVES VS. PERFORMANCE

| Objectives | Performance |
|---|---|
| implement market-based strategies to increase Express Pipeline throughput up to 15,000 barrels/day | delayed until completion of Platte Pipeline repairs in first quarter of 1999<br>received approval from U.S. regulatory authorities to use electronic in-line inspection procedure for Platte Pipeline repair/refurbishment program |
| commence expansion of Alberta Oil Sands Pipeline to handle Syncrude production growth and third-party volumes | reached agreement with Syncrude owners on an $85 million expansion of Alberta Oil Sands Pipeline<br>commenced design and engineering, working toward start-up in 2000 |
| obtain regulatory approval for expansion of Alberta Ethane Gathering System | received approval<br>completed west leg expansion<br>planned east leg expansion for completion by mid-2000 |
| continue development of northeast Alberta synthetic and heavy oil strategy | developing northeast Alberta strategy in response to producer plans and competitive initiatives |
| pursue pipeline business opportunities in South America | specific pipeline opportunities in South America being evaluated |
| add ethane extraction capability at joint venture Empress Straddle Plant by year-end | received regulatory approval<br>started construction, working toward 1999 completion |

### 1999 OBJECTIVES

- achieve operating cash flow of $85 million
- implement a growth strategy for the Cold Lake Pipeline in northeast Alberta
- complete repairs for reinstatement of the Platte Pipeline maximum operating pressure by the second quarter of 1999
- complete detailed engineering and commence construction to increase capacity of the Alberta Oil Sands Pipeline to 275,000 barrels/day by April 2000
- divest AEC's interest in Iroquois Gas Transmission System and Pan-Alberta Resources Inc.
- advance pipeline initiatives in South America to decision stage

The primary reason AEC is able to achieve a high level of growth, value and performance is its people. These employees and contractors are also the leaders, visionaries, shareholders, and entrepreneurs who make up our Company.

Highly qualified and motivated, they possess the resources and skills the Company needs to grow successfully. They are committed to continuous learning and personal growth. Their experience and expertise are diverse: from earth sciences to gas marketing, from engineering to financial management, from facility operations to information technology. Although their professions are wide-ranging, our employees are united by a common goal: to pursue opportunity and add value for AEC shareholders.

AEC's people not only expect to succeed — they do succeed. It is as a result of their teamwork, innovation and initiative that the value of AEC's assets continues to increase. AEC's people are aggressive and strong, but highly ethical competitors in their discipline.

In 1998, we saw the ranks of our employees grow from 702 to 846. Much of that increase can be attributed to our purchase of Amber Energy; more than 70% of Amber's employees accepted positions with AEC. The people that joined AEC in 1998 will play a significant role in AEC's future success.

As a Company, AEC gives each employee the opportunity and encouragement to be a life-long learner. We wholeheartedly support these professional development efforts and endeavours in the belief that having an up-to-date leading knowledge and skill set is crucial to their future and to AEC's.

**AEC has a staff of talented, enthusiastic, entrepreneurial people**

At AEC, compensation is tied to corporate, team and individual performance. Corporate and business unit results are evaluated by the Board of Directors and senior management. Team and individual performance is evaluated by management and fellow team members

The principles and concepts of "Results Based Compensation" recognize and reward employee achievements. AEC employees become shareholders through the compensation system, and stock options further stimulate results for shareholders.

Leaders in their communities as well as in our industry and their professions, our people contribute personal time and resources to a wide variety of organizations. For example, through the Go AEC (Give Once) Foundation, over the past four years, their participation, including the Company's Matching Gifts program, has generated more than $1.6 million for their charities of choice.

AEC has high expectations of its employees, just as our employees have high expectations of our Company. Our employees readily meet, and often surpass, AEC's high expectations. We have a shared vision and passion for what we do.

# Our Commitments to the Community and the Environment

**While operational reviews and financial statements reflect our performance in the business world, our community and environmental commitments reflect our interests and values in the day-to-day world. We believe our corporate contributions, and our environmental stewardship, are key to corporate citizenship in the places where we work and live.**

## Generating and sharing opportunity and wealth

AEC does more than generate opportunity and wealth—we share them. AEC is a founding sponsor of the Imagine philosophy which encourages corporate support of charitable organizations across the country.

We annually contribute at least 1% of our pre-tax profits (based on a three-year rolling average), or about $1.2 million. Part of this allocation is a matching gifts program where AEC facilitates payroll deduction for employee donations to all Canadian charities and then matches cash donations to those charities of choice.

Our contributions express our confidence in citizens' efforts to create safe, strong and vital communities. For example, the assistance we give to traditional and complementary health and wellness organizations is consistent with our corporate values which encourage healthy and balanced employee lifestyles. Our sponsorship of educational and sport programs provide youth with skills and information that will benefit them throughout their lives.

In 1998, AEC directly supported more than 120 initiatives and programs, among them:

- the Grande Prairie Mistahia Regional Health Authority's campaign to purchase a magnetic resonance imager (MRI)
- a proposed partnership with the Calgary Regional Health Authority to establish an Integrative Health Education Centre to provide quality information on complementary health and wellness practices
- DARE, a province-wide drug awareness program for Grade 6 students
- annual fundraising telethons for the Medicine Hat Public School Foundation and Medicine Hat Regional Health Foundation
- the National Sport Centre and its YES program (Youth and Education through Sport), which helps students and national-level athletes reach their career goals and aspirations and communicates shared values throughout Alberta's schools
- Northern Alberta Children's Health Foundation
- women's emergency shelters in AEC-based communities
- jointly sponsored (with the County of Grande Prairie) information meetings to help community residents cope with a prolonged series of industry-targeted crimes
- Crimestopper programs to reduce crime and vandalism
- Junior Achievement in our major areas of operation

Another aspect of our community commitment is supporting business initiatives in Aboriginal communities where we have operating interests. By doing so, we underscore a commitment to understand and respect their cultural beliefs while also offering training, business and employment opportunities. AEC has signed benefits and access agreements with 12 Aboriginal groups in Alberta, British Columbia and Northwest Territories, including a $3.5 million contract for camp construction and catering services at Maxhamish.

One of AEC's basic values and most ardent commitments is to the environment. People throughout AEC take pride in our record of safeguarding the beauty and balance of the environments in which we operate. In our pursuit to reduce emissions by improving production efficiency, we successfully applied a new technology to eliminate gas flaring during well fracture and completions. We also worked with the Tree Canada Foundation on a "carbon sink" pilot tree planting program intended to decrease the amount of carbon dioxide in the air.

As part of our "Good Neighbour" policy, we invested $200,000 in advanced technology and installed a more efficient stack burner tip at the Hythe plant. The burner enhances the reliability and efficiency of gas combustion, beyond required regulatory standards, should stack flaring be required in an operating emergency.

**Management's discussion and analysis of the financial condition and results of operations is to be read in conjunction with the Audited Consolidated Financial Statements. The Consolidated Financial Statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). A reconciliation to United States GAAP is included in Note 16 of the Notes to the Consolidated Financial Statements.**

AEC's results are reported in two business groups: Upstream comprises the Company's domestic and international gas and oil exploration, production and marketing operations. Midstream includes the Pipelines and Gas Processing segment and the Gas Storage and Hub Services operations.

Effective December 31, 1998, the Company adopted two new reporting standards established by the Canadian Institute of Chartered Accountants (CICA).

The Cash Flow Statement replaces the Statement of Changes in Financial Position. This new statement excludes non-cash transactions and results in some minor reclassifications of information.

The standard on Segment Disclosures requires the disclosure of certain information about operating segments, products and services, geographic areas and major customers. The new reporting standard results in additional disclosure in the Notes to the Consolidated Financial Statements of information previously provided outside the financial statements as Supplementary Information.

Neither of the two new standards results in any changes to Net Earnings, Cash Flow From Operations or the Consolidated Balance Sheet.

During 1997, a new Canadian accounting standard was established for Income Taxes applicable for fiscal years beginning in 2000. The Company will adopt this new standard in the applicable fiscal year. The impact of implementing the new Income Tax standard is not expected to be material, and is similar to the impact of U.S. GAAP FAS 109 as described in Note 16.

On October 23, 1998, the Company acquired control of Amber Energy Inc. (Amber) for $813.5 million as described in Note 2 of the Consolidated Financial Statements. Of the total, $776.5 million relates to upstream operations, and the balance relates to midstream operations. Results of Operations include the Amber results from that date. The acquisition was accounted for using the purchase method.

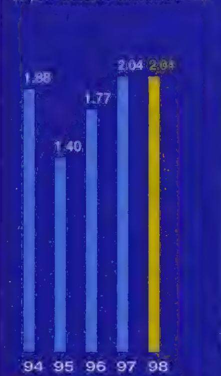
### RESULTS OF OPERATIONS: UPSTREAM

For 1998, revenues, net of royalties, increased 16% or $194.8 million, to $1,403.4 million. This compares to an increase in 1997 of 30% or $276.0 million, to $1,208.6 million. Table 1 below shows the details of these changes by product.

#### Natural Gas Prices

Natural gas prices averaged $2.04/thousand cubic feet, unchanged from 1997 (1996 - $1.77/thousand cubic feet). Prices in 1998 remained at 1997 levels as above-average winter temperatures in North America resulted in reduced demand. Additional Canadian export transportation capacity did not become available until mid-December 1998, deferring the expected reduction in the U.S./Canadian pricing differential, and reduction of an Alberta supply surplus. Despite new record levels of gas well completions, supply in western Canada increased only marginally. Natural gas liquids prices fell to $16.86 from $23.97/barrel in 1997 following the trend for crude oil (1996 - $23.95/barrel).

**Average Gas Price**
($ per thousand cubic feet)




Lack of winter demand due to warm weather kept gas prices flat

**TABLE 1 CHANGES IN OIL AND NATURAL GAS REVENUE ($ MILLIONS)**

| | 1998 Compared to 1997 | | | | | 1997 Compared to 1996 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | price | price hedge | volume | royalties & other | total | price | price hedge | volume | royalties & other | total |
| Natural Gas and NGLs | (17.5) | 2.3 | 111.7 | (0.4) | 96.1 | 56.1 | 0.4 | 38.0 | (21.2) | 73.3 |
| Oil | | | | | | | | | | |
| Conventional | (57.7) | - | (6.8) | 16.1 | (48.4) | (15.9) | - | 35.0 | (1.0) | 18.1 |
| Syncrude | (77.7) | - | 5.1 | 26.5 | (46.1) | 22.1 | - | 7.3 | 28.3 | 57.7 |
| International | (6.6) | - | 4.8 | 0.4 | (1.4) | (0.6) | - | 4.3 | (0.3) | 3.4 |
| Purchased Gas Sales | 74.1 | - | 120.5 | - | 194.6 | 106.5 | (0.2) | 17.2 | - | 123.5 |
| Total | (85.4) | 2.3 | 235.3 | 42.6 | 194.8 | 168.2 | 0.2 | 101.8 | 5.8 | 276.0 |

**TABLE 2 FACTORS AFFECTING THE PRICE OF NATURAL GAS**

| 1998 Compared to 1997 | 1997 Compared to 1996 |
|---|---|
| □ the anticipated favorable impact of increased export capacity was offset by delays in pipeline start-ups and warmer-than-average fourth quarter weather | □ increased due to summer demand to replace storage levels depleted in the colder-than-average 1996-1997 winter |

### Natural Gas Volumes

Production volumes increased to 708 million cubic feet/day from 588 million cubic feet/day in 1997 (1996 - 505 million cubic feet/day). Production in each of 1998 and 1997 includes 19 million cubic feet/day of cushion gas from the AECO Storage Facility reservoir. Natural gas sales increased to 714 million cubic feet/day, up 24% from the 1997 total of 575 million cubic feet/day (1996 – 515 million cubic feet/day). At year-end 1998, produced gas inventory in storage was 15 billion cubic feet, down from 18 billion cubic feet in 1997 as a result of the Company's increased sales (1996 – 12 billion cubic feet).

**TABLE 3 FACTORS AFFECTING NATURAL GAS SALES AND PRODUCTION VOLUMES**

| 1998 Compared to 1997 | 1997 Compared to 1996 |
|---|---|
| □ new production brought on stream at Primrose, Suffield, Berland River and a second quarter plant expansion at Fontas<br>□ sale of 3 billion cubic feet of gas held in inventory<br>□ addition of Amber volumes from October 24, 1998 | □ new production was brought on stream at Primrose in the second quarter and Gold Creek in the fourth quarter<br>□ unscheduled facility maintenance<br>□ decision to retain gas in storage in expectation of an improvement in prices in the first quarter of 1998 |

Purchased gas sales increased to 752 million cubic feet/day from 569 million cubic feet/day in 1997 (1996 – 532 million cubic feet/day). Revenue from the sale of purchased gas increased to $570.7 million from $376.1 million in 1997 (1996 - $252.7 million). The operating loss increased from $3.8 million to $7.9 million primarily due to increased cost of operations. At December 31, 1998, the Company had contracts in place to purchase 125.4 billion cubic feet of natural gas over a two-year period. Contracts were also in place to deliver 136.8 billion cubic feet over the same period. At year-end, there were 17 billion cubic feet of purchased gas in inventory (1997 - nil; 1996 – 3 billion cubic feet).

### Crude Oil Prices

Prices for Canadian conventional crude oil averaged $13.13/barrel, a 34% decrease from $19.99/barrel during 1997. In 1996, the average price received was $21.80/barrel. Prices for Syncrude Sweet Blend oil averaged $20.46/barrel compared to $27.80/barrel in 1997, a 26% decrease (1996 – $25.68/barrel). Argentinean oil prices averaged $17.44/barrel, a decrease of 29% from the 1997 average price of $24.66/barrel (1996 – $25.57/barrel).

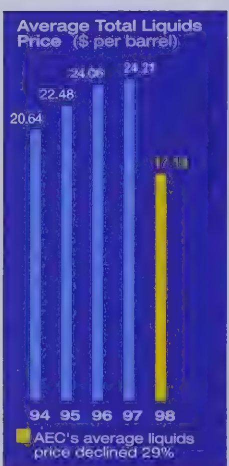



**TABLE 4 FACTORS AFFECTING OIL PRICES**

| 1998 Compared to 1997 | 1997 Compared to 1996 |
|---|---|
| □ West Texas Intermediate (WTI) prices declined 30% from an average US$20.61 in 1997 to US$14.43 in 1998; this was partially offset by a decrease in Canadian dollar to U.S. dollar exchange rates average from $0.722 to $0.674<br>□ the general decrease in oil prices was partially offset as the heavy oil price differential narrowed | □ WTI prices declined from an average US$22.01 in 1996 to US$20.61 in 1997; this was partially offset by an increase in the U.S. to Canadian foreign exchange rates<br>□ an increase in the proportion of conventional heavy crude grades sold at lower prices reduced the average price/barrel of Canadian conventional crude oil and was partially offset by the elimination of hedging costs |

### Crude Oil and Natural Gas Liquids Volumes

AEC produced an average of 23,027 barrels/day of Canadian conventional oil in 1998, compared to the 23,954 barrels/day produced in 1997, a decrease of 4% (1996 – 19,507 barrels/day). Natural gas liquids volumes increased 21% to 5,877 barrels/day from 4,856 barrels/day (1996 - 4,811 barrels/day). Syncrude sales averaged 28,953 barrels/day, an increase of 2% over the 28,447 barrels/day sold in 1997 (1996 – 27,596 barrels/day). AEC's international production amounted to 2,217 barrels/day in 1998, an increase of 32% over the 1,683 barrels/day produced in 1997 (1996 – 1,241 barrels/day).

**TABLE 5 FACTORS AFFECTING OIL PRODUCTION**

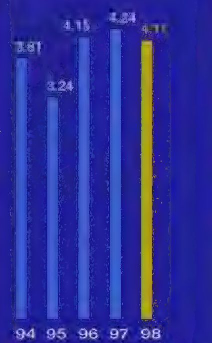
**1998 Compared to 1997**

- annual volumes increased due to the Amber acquisition and slightly higher production from AEC International and AEC Syncrude
- declining oil prices led the Company to reduce conventional crude development
- unscheduled maintenance at Syncrude restricted production in the third and fourth quarters

**1997 Compared to 1996**

- oil production brought on stream at Suffield, Valhalla and Clairmont
- minor property disposals resulted in a decrease of 1,100 barrels/day

**Upstream Conventional Operating Cost**
($ per barrel of oil equivalent)




Operating Costs declined 3% per barrel of oil equivalent, net of gas processing fees

During 1997, AEC began accessing new U.S. markets via the indirect 50%-owned Express Pipeline System.

### Production Unit Netbacks

Production unit netbacks represent the Operating Cash Flow the Company receives, on average, for each unit of product sold. Natural gas netbacks remained constant at $1.33/thousand cubic feet, the same as 1997. Netbacks for conventional oil declined 40% to $6.44/barrel in 1998, compared to $10.67/barrel in 1997; and netbacks for Syncrude Sweet Blend averaged $7.33/barrel in 1998, a decrease of 39% over the $11.97/barrel received in 1997. At the end of 1996, all of AEC's oil price swaps terminated.

Netbacks received by AEC over the past three years and the factors affecting them are summarized below:

**TABLE 6 PRODUCT UNIT NETBACK ($ PER UNIT)**

| | Natural Gas (thousand cubic feet) | | | Conventional Oil (barrel) | | | Syncrude (barrel) | | |
|---|---|---|---|---|---|---|---|---|---|
| | **1998** | 1997 | 1996 | **1998** | 1997 | 1996 | **1998** | 1997 | 1996 |
| Revenue | **2.04** | 2.04 | 1.80 | **13.13** | 19.99 | 25.14 | **20.46** | 27.80 | 29.08 |
| Hedge | **-** | - | (0.03) | **-** | - | (3.34) | **-** | - | (3.40) |
| Revenue, net of hedge | **2.04** | 2.04 | 1.77 | **13.13** | 19.99 | 21.80 | **20.46** | 27.80 | 25.68 |
| GORR * | **-** | - | - | **-** | - | - | **0.51** | 0.69 | 0.71 |
| Royalties | **0.29** | 0.31 | 0.20 | **1.82** | 3.58 | 4.28 | **(0.03)** | 2.70 | 5.58 |
| Operating Costs | **0.42** | 0.40 | 0.43 | **4.87** | 5.74 | 4.69 | **13.67** | 13.82 | 13.71 |
| Netback | **1.33** | 1.33 | 1.14 | **6.44** | 10.67 | 12.83 | **7.33** | 11.97 | 7.10 |

** Gross Overriding Royalty Received*

**TABLE 7 FACTORS AFFECTING UNIT NETBACKS**

| | 1998 Compared to 1997 | 1997 Compared to 1996 |
|---|---|---|
| **Natural Gas** | □ higher per-unit operating costs, due in part to higher custom processing of third-party volumes, were partially offset by processing fee revenue earned | □ increase in prices and lower per unit operating costs more than offset an increase in royalties per unit |
| **Conventional Oil** | □ a decrease in the average price was partially offset by a decrease in royalties, lower heavy oil price differentials, lower foreign exchange rates and lower operating costs<br>□ the addition of Amber volumes lowered AEC's average unit operating costs | □ a decrease in average price and increased costs of production were partially offset by the elimination of the oil price hedging losses and a decrease in royalties paid<br>□ delayed tie-ins increased oil hauling costs |
| **Syncrude Sweet Blend Oil** | □ lower oil prices were partially offset by lower foreign exchange rates and lower operating costs<br>□ royalties decreased as a result of new fiscal terms established by the Government of Alberta | □ Crown royalties decreased as a result of new fiscal terms established by the Government of Alberta<br>□ the oil price decline was more than offset by the elimination of the hedge costs incurred in 1996 |

### Upstream Capital

During 1998, the Upstream business group invested capital of $767.7 million (1997 - $778.0 million). Proceeds received on the disposal of non-core oil and gas properties amounted to $25.3 million.

Investment in the Western Canadian Sedimentary Basin amounted to $609.8 million and resulted in the addition of 778 billion cubic feet equivalent of proven reserves, and 211 billion cubic feet equivalent of probable reserves or 989 billion cubic feet equivalent in total. Major exploration and development activities undertaken in the West Peace River Arch, at Suffield and Primrose, and in newer plays at Edson, Maxhamish and Pelican Lake, contributed to the significant reserves additions of 1998.

Finding and development costs are a measure of an exploration company's ability to economically find and exploit new oil and gas reserves. In 1998, the Company invested $6.16/barrel on a proven plus probable basis compared to $5.81/barrel in 1997, using a natural gas to oil conversion ratio of 10 thousand cubic feet of natural gas to one barrel of oil.

Some of the more notable activities included three successful exploration wells drilled in the Edson area; one gas well drilled at Smoky in west central Alberta with a sustainable production rate of 10 million cubic feet/day to AEC; eight horizontal wells drilled and one battery constructed at Pelican Lake; 560 gas well recompletion program completed and 285 shallow gas wells drilled at Suffield; 60 gas development wells drilled at Primrose; a Primrose storage facility developed with a capacity of 25 billion cubic feet; a Berland River gas well producing 13 million cubic feet/day net to AEC on production in November; three exploration wells drilled in the Tupper area of British Columbia and a pipeline constructed to the Hythe gas plant; and development of the Maxhamish area commenced including a gas plant with a design capacity of 70 million cubic feet/day.

Investments were also made in the ongoing development of a pilot project which has confirmed the potential of producing heavy crude reserves utilizing steam-assisted gravity drainage (SAGD) technology. In addition, $13.2 million was invested in exploration projects in North Dakota and Montana.

The Company periodically evaluates the future value of its oil and gas reserves and compares them to the accounting value of those reserves. This evaluation is as prescribed in the Canadian Generally Accepted Accounting Principles Full Cost Accounting Guideline and is known as the ceiling test. At year-end, the Company's reserve value exceeded the specified cost base by $766 million.

Investments in AEC Syncrude totaled $68.3 million primarily directed to sustaining production, developing the Aurora mine, removing production constraints and acquiring two new leases.

Investments in AEC International operations amounted to $64.7 million. In addition to continuing exploration and development operations in Argentina, the Company has a 25% interest in a successful gas well in the Australian Northwest Shelf. Further drilling will be required to appraise the size of the discovery.

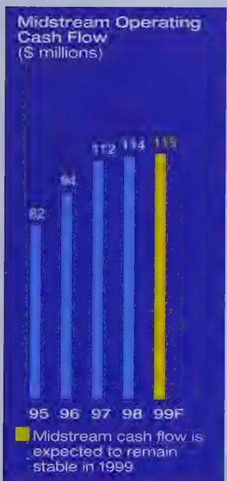
Low oil prices at year-end and a decision to discontinue operations in Thailand resulted in additional depletion in the amount of $14.0 million being recorded relating to international properties.

## RESULTS OF OPERATIONS: MIDSTREAM

For 1998, Midstream revenues of $506.5 million were comparable to $508.3 million in 1997 (1996 - $189.5 million). The factors contributing to this decrease are detailed below:

**TABLE 8 FACTORS AFFECTING MIDSTREAM REVENUE**

| | 1998 Compared to 1997 | 1997 Compared to 1996 |
|---|---|---|
| **Pipelines** | □ decreased due to lower oil sales revenue of a 50%-owned affiliate shipping on the Express Pipeline System; this was partially offset by an increase in revenues due to full year operation of the Express Pipeline System compared to nine months in 1997 | □ increased due to the sale of oil acquired to fulfill volume obligations on the Express Pipeline System<br>□ increased due to the commissioning of the Express Pipeline System |
| **Natural Gas Storage** | □ revenues increased due to increasing emphasis on the optimization of the facility which involved the purchase and sale of natural gas | □ net revenues are comparable year over year |
| **Natural Gas Liquids Processing** | □ revenues declined as natural gas liquids prices followed the decline in oil prices | □ increased primarily due to the full-year impact of the Empress Straddle Plant operations |




Throughput capacity on the Express Pipeline System has been constrained as a consequence of line pressure restrictions imposed on the Platte Pipeline segment of the system following a pipeline leak on July 2, 1997. A complete assessment was conducted and a pressure reinstatement program is underway and expected to be completed by the end of the first quarter of 1999. Capital investment in the Pipelines group amounted to $68.5 million in 1998.

The Company holds a 50% ownership in an affiliate that is a shipper on the Express Pipeline System. The revenue from oil sold and the cost of oil purchased and shipped on the Express System is reflected in revenue and cost of product purchased, respectively. Affiliate revenue included in the Pipelines total amounted to $219.8 million in 1998 as compared to $259.5 million in 1997 reflecting lower average oil prices (1996 - nil).

During 1997, the Company restructured its crude oil pipeline operations with the formation of AEC Pipelines, L.P., as more fully described in Note 3 of the Notes to the Consolidated Financial Statements. This transaction enabled a market valuation to be placed on the Company's crude oil pipeline assets and provided additional capital to fund expanded operations, most notably the development of Express Pipeline System.

In 1998, the Company invested $43.2 million in its gas storage operations, $27.0 million of which related to the ongoing construction of the new 14-billion cubic foot Wild Goose Gas Storage Facility in California. This facility is expected to be in service in the second quarter of 1999. During the year, the Company accelerated a program of natural gas purchases and sales designed to optimize utilization of the Suffield facility. This resulted in gas sales of $34.0 million which is included in Gas Storage Revenue.

### Consolidated Summary

Consolidated Net Earnings for 1998 amounted to $24.4 million, compared to $21.7 million in 1997 (1996 - $68.0 million). Including the 1997 dilution gain, Net Earnings in 1997 were $199.7 million. Consolidated Cash Flow from Operations decreased 10% to $488.5 million in 1998 from $544.7 million in 1997 (1996 - $411.9 million). Consolidated Net Revenues for 1998 totaled $1,909.9 million, compared to $1,716.9 million in 1997, an 11% increase (1996 - $1,122.1 million).

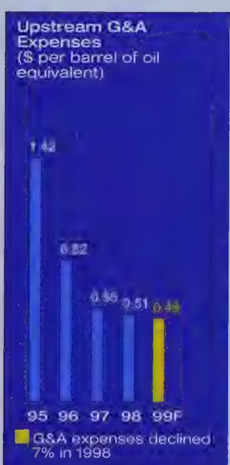
Factors affecting these results are outlined in the following table:

**TABLE 9 FACTORS AFFECTING CONSOLIDATED RESULTS**

| | 1998 Compared to 1997 | 1997 Compared to 1996 |
|---|---|---|
| **Net Earnings** | $24.4 million, down $175.3 million<br>□ $178.0 million lower due to the dilution gain recorded in 1997<br>□ less additional depletion<br>□ lower oil contributions<br>□ higher interest expense<br>□ lower income tax<br>□ decrease in Pipelines earnings<br>□ lower straddle plant processing earnings | $199.7 million, up $131.7 million<br>□ $178.0 million dilution gain representing the increase in the Company's share of the accounting value of AEC Pipelines, L.P. partnership equity resulting from the sale of a 30% minority interest<br>□ additional depletion related to AEC International operations<br>□ increase in Syncrude netbacks<br>□ minority interest in AEC Pipelines, L.P.<br>□ increase in natural gas prices<br>□ decrease in net interest expense<br>□ decrease in general and administrative expense |
| **Cash Flow from Operations** | $488.5 million, down $56.2 million<br>□ decrease in oil operating cash flow<br>□ increase in produced gas operating cash flow<br>□ higher cash interest expense<br>□ lower cash income tax<br>□ increases in Gas Storage and Hub Services and Pipelines operating cash flow<br>□ decrease in straddle plant processing operating cash flow | $544.7 million, up $132.8 million<br>□ increased natural gas prices and volumes<br>□ increased Syncrude prices and volumes<br>□ newly commissioned Express Pipeline System<br>□ full-year impact of Empress Straddle Plant<br>□ decreased purchased gas operating margins and increased pipeline transportation costs |
| **Net Revenues** | $1,909.9 million, up $193.0 million<br>□ increased purchased gas prices and volumes<br>□ lower oil and NGLs prices<br>□ increased produced gas volumes<br>□ higher gas storage revenues<br>□ lower pipeline affiliate oil sales<br>□ lower Syncrude royalties<br>□ lower straddle plant processing revenues<br>□ higher pipelines revenue | $1,716.9 million, up $594.8 million<br>□ marketing of purchased oil volumes<br>□ increased purchased gas prices and volumes<br>□ increased produced gas prices and volumes<br>□ increased Syncrude prices and volumes<br>□ full-year impact of Empress Straddle Plant |

**TABLE 10 FACTORS AFFECTING EXPENSES**

| | 1998 Compared to 1997 | 1997 Compared to 1996 |
|---|---|---|
| **Operating Expenses** | $488.8 million, up $38.3 million<br>□ higher produced gas costs were partially due to higher third-party volumes processed<br>□ higher pipeline operating costs<br>□ lower straddle plant feedstock costs | $450.5 million, up $78.4 million<br>□ commissioning and operating the Express Pipeline System<br>□ full-year impact of Empress Straddle Plant<br>□ new oil and natural gas production brought on stream |
| **Cost of Product Purchased** | $816.3 million, up $185.3 million<br>□ higher purchased gas volumes and costs<br>□ lower crude oil purchase costs<br>□ higher gas storage optimization costs | $631.0 million, up $384.6 million<br>□ increase due to the purchase of oil acquired by a 50%-owned affiliate to fulfill volume obligations on the Express Pipeline System<br>□ increase due to higher volumes of purchased gas trading activity and higher unit costs |
| **General and Administrative Expenses** | $30.4 million, up $2.3 million<br>□ higher staff levels, information technology and shareholder costs | $28.1 million, down $4.3 million<br>□ lower information technology expenses, consulting and transportation costs |
| **Net Interest Expense** | $84.7 million, up $35.8 million<br>□ higher monthly average debt levels and cost of borrowing partially offset by a foreign exchange gain related to the Express Pipeline System financing | $48.9 million, down $4.5 million<br>□ higher monthly average debt levels offset by lower cost of borrowing |
| **Depreciation, Depletion and Amortization** | $385.6 million, up $29.1 million<br>□ higher natural gas volumes were partially offset by a lower per-unit rate of $0.93 compared to $1.02/million cubic feet equivalent in 1997 | $356.5 million, up $70.7 million<br>□ higher natural gas and oil volumes sold<br>□ higher per-unit rate of $1.02 compared to $0.96/million cubic feet equivalent in 1996 |
| **Additional Depletion and Amortization** | $14.0 million, down $70.9 million<br>□ International ceiling tests | $84.9 million<br>□ International ceiling tests completed on a country basis - $72.4 million<br>□ exited Peru and Trinidad<br>□ Argentina operations continue<br>□ additional amortization of midstream capital assets |
| **Income Taxes** | $47.3 million, down $33.2 million<br>□ impact of lower taxable earnings was partially offset by lower non-deductible additional depletion costs | $80.5 million, up $1.5 million<br>□ lower effective tax rate in 1997 as a result of the non-taxable dilution gain partially offset by non-deductible additional depletion and amortization |




During 1998, the Canadian dollar declined in value relative to the U.S. dollar. Approximately 76% of the Company's production revenue is denominated directly or indirectly in U.S. dollars and is subject to changes in exchange rates. As a result of the lower Canadian dollar in 1998, the Company's revenue was higher by approximately $35 million. These gains were partially offset by $9.6 million of foreign exchange costs relating to the Company's U.S.-dollar denominated long-term debt. In Canada, exchange gains and losses are deferred and amortized over the term of the associated long-term debt. The impact of expensing these costs is as described in Note 16 of the Notes to the Consolidated Financial Statements.

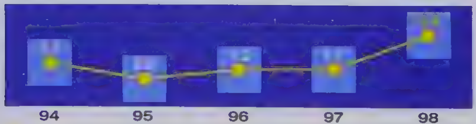
## LIQUIDITY AND CAPITAL RESOURCES

Excluding the Amber acquisition, on a consolidated basis, the Company invested $883.3 million of which $767.7 million, or 87%, was in the Upstream business group, and $115.6 million in the Midstream business group, including $41.9 million of indirect pipelines capital. In 1997, the Company invested $984.4 million. Factors affecting capital are detailed below:

**TABLE 11 ALLOCATION OF CAPITAL INVESTED**

| | 1998 | 1997 |
|---|---|---|
| **Western Canada Conventional Oil and Gas** | $609.8 million<br>□ $312.3 million on exploration and development drilling<br>□ $188.2 million on production facilities<br>□ $109.3 million on land and seismic | $669.4 million<br>□ securing a large land position in key exploration areas<br>□ drilling 391 net wells<br>□ developing required gas and oil processing capability |
| **Syncrude** | $68.3 million<br>□ ongoing mine expansion and capital improvements | $48.8 million<br>□ commencing new mine and expansion development plan |
| **International** | $64.7 million<br>□ $42.8 million on exploration and development in Argentina<br>□ $16.8 million on exploration wells on the Australian Northwest Shelf<br>□ $5.1 million in other countries | $48.3 million<br>□ drilling and development in Argentina<br>□ conducting exploration assessments in two countries |
| **U.S. Upstream** | $13.2 million | $9.5 million |
| **Express Pipeline System** | $25.8 million<br>□ refurbishing the Platte System from Casper, Wyoming to Wood River, Illinois<br>□ ongoing capital improvements | $120.5 million<br>□ commissioning of pipeline from Hardisty, Alberta to Casper, Wyoming<br>□ refurbishing the Platte System from Casper, Wyoming to Wood River, Illinois |
| **Other Pipelines** | $42.7 million<br>□ investments in AEC Pipelines, L.P., holder of Alberta Oil Sands and Cold Lake pipelines, and in directly held pipelines | $39.1 million<br>□ investments in Lakeland, Alberta Oil Sands and Cold Lake pipelines |
| **Gas Storage** | $43.2 million<br>□ construction of the Wild Goose Gas Storage Facility<br>□ construction of the AECO storage expansion in northwestern Alberta | $40.2 million<br>□ acquiring natural gas volumes to be used in the maintenance of facility deliverability pressures<br>□ commencing construction of the Wild Goose Gas Storage facility in California |
| **Natural Gas Liquids Processing** | $3.9 million<br>□ facility expansion | ($2.5) million<br>□ cost recovery equalization on admission of a new joint venture participant |

**Upstream Debt-to-Cash Flow**
(times, excludes Amber)




Upstream balance sheet is prudently financed at the bottom of the price cycle


The Company funded its investment program primarily through a combination of Cash Flow From Operations of $488.5 million, proceeds on the disposal of non-core assets of $25.3 million and long-term debt. The acquisition of Amber was funded with a combination of long-term debt, AEC shares and Amber debt assumed.

On a consolidated basis, long-term debt held directly by the Company was $1,646.7 million at December 31, 1998, up $639.9 million, from the 1997 amount of $1,006.8 million. The Company has ten revolving credit facilities available to a maximum of $1,592 million for terms ranging from four months to eight years. At December 31, 1998, $535 million or 34% was utilized. In addition, the Company has the capability to issue up to $150 million of Unsecured Debentures by way of a medium-term note shelf prospectus, until August 2000. Total debt is $1,977.4 million, (1997-$1,017.1 million) of which $330.7 million is the Company's proportionate share of debt of affiliates.

The Company maintains a separate capital structure for each of its Upstream and Midstream business groups consistent with the norms for those industries to recognize the different business profiles, risk and rewards associated with each. The Midstream business group's debt is comprised of indirect debt held by the Express Pipeline System, AEC Pipelines, L.P., Pan-Alberta Resources Inc. and allocated AEC debt to establish an industry benchmark debt-to-capitalization ratio of 60:40.

At December 31, 1998, $1,355.4 million of long-term debt was related to upstream operations and $622.0 million was included in midstream operations, of which $330.7 million was indirect.

## RISK MANAGEMENT

The Company's results are influenced by factors such as product prices, interest and foreign exchange rates, royalties, taxes and operations. Sensitivities to some of these factors are summarized below:

| Factor | 1999 Impact on Cash Flow $ | Per Share |
|---|---|---|
| Change of US$0.10/thousand cubic feet in the price of natural gas | $42 million | $0.30 |
| Change of US$1.00 WTI/barrel in the price of oil | $37 million | $0.27 |
| Change of $0.01 in the value of the Canadian dollar relative to the U.S. dollar | $16 million | $0.11 |

The Company seeks to manage its risk exposure through a combination of insurance, internal controls, sound operating practices and financial derivatives. Derivatives such as commodity price swap agreements, interest rate swaps and foreign exchange forward-sale contracts are used only to reduce specific risk exposures and are not held for trading purposes.

During 1998, the Company utilized commodity price swaps for produced gas and purchased gas, and an affiliate utilized oil price swaps. At October 23, 1998, Amber had in place floating-to-fixed interest rate swaps and foreign exchange forward sales contracts. Foreign exchange contract losses of $11.4 million at the date of acquisition were accrued and included in the purchase price.

In addition to limits established by the Board of Directors on the use of commodity price swap agreements, a rigorous system of internal control procedures has been established. Credit risks are managed by transacting only with pre-authorized counterparties where agreements are in place. Credit limits are established for all parties where a credit risk exposure exists and are closely monitored.

An active program of monitoring and reporting day-to-day operations is designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for timely response to an event.

AEC is exposed to risks and uncertainties inherent in foreign operations, including regulatory and legislative changes. Events in these operations are not expected to have a material adverse effect on the Company.

## YEAR 2000 READINESS

The Company instituted a corporate-level Year 2000 (Y2K) Program in the fall of 1997. The Program has dedicated, full-time staff who provide core project management services to assist the business groups in addressing Y2K issues. Additional external resources are contracted to meet specific skill requirements or staffing levels to ensure the timely execution of the Program. Progress reports are presented to Senior Management and to the Audit Committee of the Board of Directors.

AEC is addressing Y2K issues in five overlapping phases:

(1) corporate-wide awareness of the issue;
(2) identification and assessment of all critical equipment, software systems, facilities and business relationships;
(3) detailed planning of remediation and testing as well as contingency planning;
(4) remediation and testing of critical items;
(5) implementation of procedures to maintain a Y2K-ready environment.

The Company has implemented these phases across four broad areas: Field Process Control; Information Technology Systems; Facilities Systems; and External Business Relations.

The Company believes it is impractical to seek to eliminate all potential Y2K issues before they arise. The Company is using a risk-based analysis of its operations to identify those items deemed to be "mission critical", defined as having the potential for significant adverse effects in one or more of five areas: environmental, safety, ongoing business relationships, financial and legal exposure, and Company credibility and image.

The Company uses a series of "scorecards" and planning documents to monitor and track the progress of the Year 2000 Program. The Year 2000 Program is proceeding on schedule. While the Program has targeted June 30, 1999 to complete all the remediation and testing of critical items, certain items may be delayed to coincide with scheduled plant maintenance activities and some business continuity/contingency planning activities may be completed after the target date. The Company is dedicated to having addressed all mission-critical items by December 31, 1999.

The Company utilizes both internal and external resources in its Y2K efforts. The Company has estimated that total costs for the Year 2000 Program will not exceed $9 million. This estimate does not include AEC's potential share of Y2K costs that may be incurred by partnerships and joint ventures in which the Company participates but is not the operator. In 1998, approximately $750,000 was spent on Y2K issues.

The Company has already developed and maintains extensive contingency plans to respond to equipment failures, emergencies and business interruptions. Contingency planning for Y2K issues is complicated by the possibility of multiple and simultaneous incidents which could significantly impede efforts to respond to emergencies and resume normal business functions. Such incidents may be outside the Company's control if, for example, mission-critical third parties do not successfully address their own material Y2K problems. The Company is developing contingency plans which it expects to have in place by the second half of 1999 to identify potential problems and mitigate the impact on its operations of potential failures arising from the Y2K issue. These plans will be designed to protect the Company's assets, continue safe operations, protect the environment, and enable the resumption of any interrupted operations in a timely and efficient manner.

## OUTLOOK

Oil and gas sales are targeted to grow, while commodity prices remain volatile. The combined outlook in Cash Flow and Net Earnings will be driven by both factors. Produced gas sales are expected to grow 26% to 900 million cubic feet/day compared to 714 million cubic feet/day in 1998. The Company believes it has secured adequate gas pipeline transportation to achieve its forecasted direct sales volumes. At the time of writing, 75% of AEC's 1999 produced gas sales are committed. The remaining uncommitted volumes comprise 15% of total sales targeted to markets outside Alberta, and 10% of total sales targeted to markets inside Alberta. Storage inventory is forecast to be 18 billion cubic feet of produced gas at the beginning of the 1999 - 2000 winter heating season, and 3 billion cubic feet at December 31, 1999. Sales of oil and liquids are expected to grow to 72,000 barrels/day with approximately the following mix:

| | |
|---|---|
| □ Light and NGLs | 67% |
| □ Heavy | 33% |

Alberta natural gas prices have strengthened as additional export capacity came on stream in late 1998 providing access to U.S. markets and reducing the gas-on-gas competition within Alberta. We expect this will result in Alberta prices being stronger than prices from U.S. markets in 1999.

During 1999, oil prices are expected to remain near current levels of US$12 WTI due to continued soft demand and increasing world production. Oil netbacks per unit are expected to be near 1998 levels.

In 1998, the Company entered into a number of one-year term sale agreements commencing January 1, 1999 with heavy oil purchasers to reduce the risk of widening light-to-heavy differentials on approximately 16,000 barrels/day of blended heavy oil. Twenty-eight percent of this volume was locked in at a fixed differential equivalent to a WTI-to-Bow River differential of US$3.75/barrel. Sixty-six percent of this volume was locked in at a “cap” which is equivalent to a WTI-to-Bow River differential of US$4.00/barrel. This provides the Company the market differential up to a maximum of US$4.00/barrel and is fixed at US$4.00/barrel if differentials widen further. The remaining 6% is priced at a wellhead floor price or on a percentage of light crude price.

Also in 1998, Amber had in place, a contract to deliver 5,000 barrels/day of blended heavy crude oil for a term of one year ending August 31, 1999 at a fixed differential to WTI of US$4.65/barrel with a heavy oil refiner.

In 1999, AEC expects its direct capital investment in core programs to be approximately $750 million.

Upstream capital investment is estimated to be $700 million directed to natural gas and oil exploration and development activities. AEC is targeting to drill up to 600 gross wells in 1999, the majority of which will target natural gas. At Maxhamish, production facilities capable of 70 million cubic feet/day will be completed during the first quarter of 1999 with commercial production expected to commence in the second quarter.

Capital investments in Syncrude of approximately $900 million (AEC share) over the next ten years are expected to approximately double AEC’s share of production to over 56,000 barrels/day and reduce production costs to under $10/barrel, in 1998 dollars, by 2007.

Direct midstream operations are targeting $50 million in investments and expect to generate stable Operating Cash Flow as a result of improvements in the pipeline operations and additional new gas storage capacity, offsetting decreases due to potential minor dispositions.

The Company will continue to assess the way in which it finances its operations to achieve its growth targets in a financially-prudent manner. The Company intends to finance its 1999 budgeted capital program through Cash Flow from Operations, long-term debt and other financing vehicles that optimize full-cycle capital returns.

February 17, 1999

# Management Report

The accompanying Consolidated Financial Statements and all information in this annual report are the responsibility of Management. The financial statements have been prepared by Management in accordance with Canadian Generally Accepted Accounting Principles and include certain estimates that reflect Management's best judgements. Financial information contained throughout this annual report is consistent with these financial statements.

The Company has developed and maintains an extensive system of internal control that provides reasonable assurance that all transactions are accurately recorded, that the financial statements realistically report the Company's operating and financial results and that the Company's assets are safeguarded. The Company's Internal Audit department reviews and evaluates the adequacy of and compliance with the Company's internal controls. As well, it is the policy of the Company to maintain the highest standard of ethics in all its activities.

AEC's Board of Directors has approved the information contained in the financial statements. The Board fulfills its responsibility regarding the financial statements mainly through its Audit Committee.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last Annual Meeting to audit the Consolidated Financial Statements and provide an independent professional opinion.

D Watson

**Gwyn Morgan**
***President & Chief Executive Officer***
***February 17, 1999***

**John D. Watson**
***Vice-President, Finance & Chief Financial Officer***

# Auditors' Report

**To the Shareholders of Alberta Energy Company Ltd.:**

We have audited the Consolidated Balance Sheets of Alberta Energy Company Ltd. as at December 31, 1998 and December 31, 1997 and the Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the years in the three-year period ended December 31, 1998. These financial statements are the responsibility of the Company's Management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Generally Accepted Auditing Standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 1998 and December 31, 1997 and the results of its operations and the changes in its cash position for each of the years in the three-year period ended December 31, 1998, in accordance with Generally Accepted Accounting Principles in Canada.

PricewaterhouseCoopers LLP

**Chartered Accountants**
***Calgary, Canada***
***February 5, 1999***

# Consolidated Statement Of Earnings

| Year Ended December 31 ($ millions, except per share amounts) | 1998 | 1997 | 1996 |
|---|---|---|---|
| Revenues, Net of Royalties | | | |
| Upstream | $ 1,403.4 | $ 1,208.6 | $ 932.6 |
| Midstream (Note 4) | 506.5 | 508.3 | 189.5 |
| | 1,909.9 | 1,716.9 | 1,122.1 |
| Costs, Expenses and Other | | | |
| Operating | 488.8 | 450.5 | 372.1 |
| Cost of product purchased | 816.3 | 631.0 | 246.4 |
| General and administrative | 30.4 | 28.1 | 32.4 |
| Interest, net (Note 5) | 84.7 | 48.9 | 53.4 |
| Depreciation, depletion and amortization | 385.6 | 356.5 | 285.8 |
| Additional depletion and amortization (Note 8) | 14.0 | 84.9 | - |
| Dilution gain (Note 3) | - | 178.0 | - |
| Earnings Before the Undernoted | 90.1 | 295.0 | 132.0 |
| Income taxes (Note 6) | 47.3 | 80.5 | 79.0 |
| Minority interest | 18.4 | 14.8 | - |
| Net Earnings from Continuing Operations | 24.4 | 199.7 | 53.0 |
| Net Earnings from Discontinued Operations (Note 3) | - | - | 15.0 |
| Net Earnings | $ 24.4 | $ 199.7 | $ 68.0 |
| Earnings from Continuing Operations per Common Share | | | |
| Basic | $ 0.21 | $ 1.78 | $ 0.51 |
| Fully diluted | $ 0.21 | $ 1.73 | $ 0.51 |
| Earnings per Common Share | | | |
| Basic | $ 0.21 | $ 1.78 | $ 0.65 |
| Fully diluted | $ 0.21 | $ 1.73 | $ 0.65 |

*See accompanying Notes to the Consolidated Financial Statements*

# Consolidated Statement Of Retained Earnings

| Year Ended December 31 ($ millions) | 1998 | 1997 | 1996 |
|---|---|---|---|
| Balance, Beginning of Year | $ 648.2 | $ 493.0 | $ 464.7 |
| Net Earnings | 24.4 | 199.7 | 68.0 |
| | 672.6 | 692.7 | 532.7 |
| Common Share Dividends | (45.0) | (44.5) | (39.7) |
| Balance, End of Year | $ 627.6 | $ 648.2 | $ 493.0 |

*See accompanying Notes to the Consolidated Financial Statements.*

# Consolidated Balance Sheet

| As at December 31 ($ millions) | 1998 | 1997 |
|---|---|---|
| **ASSETS** | | |
| Current Assets | | |
| Cash | $ 29.7 | $ 44.8 |
| Accounts receivable and accrued revenue | 370.2 | 325.5 |
| Inventories (Note 7) | 139.7 | 72.8 |
| | 539.6 | 443.1 |
| Capital Assets (Note 8) | 5,224.2 | 3,907.8 |
| Investments and Other Assets (Note 9) | 95.9 | 47.0 |
| | $ 5,859.7 | $ 4,397.9 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| Current Liabilities | | |
| Accounts payable and accrued liabilities | $ 427.0 | $ 386.8 |
| Current portion of long-term debt | 1.8 | 1.5 |
| | 428.8 | 388.3 |
| Long-Term Debt (Note 10) | 1,646.7 | 1,006.8 |
| Indirect Midstream Long-Term Debt (Note 11) | 330.7 | 10.3 |
| Other Liabilities (Note 12) | 134.6 | 79.2 |
| Deferred Income Taxes | 630.7 | 585.4 |
| Minority Interest, AEC Pipelines, L.P. | 108.3 | 114.2 |
| | 3,279.8 | 2,184.2 |
| Shareholders' Equity | | |
| Share Capital (Note 13) | 1,916.0 | 1,546.0 |
| Retained Earnings | 627.6 | 648.2 |
| Foreign Currency Translation Adjustment | 36.3 | 19.5 |
| | 2,579.9 | 2,213.7 |
| | $ 5,859.7 | $ 4,397.9 |

*See accompanying Notes to the Consolidated Financial Statements.*

Approved by the Board

**Director** **Director**

# Consolidated Statement of Cash Flows

| Year Ended December 31<br>($ millions except per share amounts) | 1998 | 1997 | 1996 |
|---|---|---|---|
| **OPERATING ACTIVITIES** | | | |
| Net Earnings from Continuing Operations | $ 24.4 | $ 199.7 | $ 53.0 |
| Depreciation, depletion and amortization | 385.6 | 356.5 | 285.8 |
| Additional depletion and amortization | 14.0 | 84.9 | - |
| Deferred income taxes | 47.9 | 67.8 | 70.6 |
| Minority interest | 18.4 | 14.8 | - |
| Dilution gain | - | (178.0) | - |
| Other | (1.8) | (1.0) | 2.5 |
| Cash Flow from Operations | 488.5 | 544.7 | 411.9 |
| Net change in non-cash working capital (Note 15) | (59.6) | (84.8) | (50.8) |
| | 428.9 | 459.9 | 361.1 |
| **INVESTING ACTIVITIES** | | | |
| Acquisition (Note 2) | (303.2) | - | (365.0) |
| Capital investment | (883.3) | (984.4) | (908.0) |
| Net proceeds on sale of AEC Pipelines, L.P. (Note 3) | - | 295.4 | - |
| Proceeds on disposal of assets (Note 3) | 25.3 | 195.0 | 66.5 |
| Investments and other | (10.5) | - | (9.9) |
| Net change in non-cash working capital (Note 15) | (9.5) | (9.9) | 80.7 |
| | (1,181.2) | (503.9) | (1,135.7) |
| (Decrease) Increase in Cash Before Financing Activities | (752.3) | (44.0) | (774.6) |
| **FINANCING ACTIVITIES** | | | |
| Issue of long-term debt | 693.7 | 142.1 | 682.5 |
| Repayment of long-term debt | (110.8) | (100.7) | (149.3) |
| Issue of Common Shares (Note 13) | 220.0 | 14.0 | 293.6 |
| Common Share dividends | (45.0) | (44.5) | (39.7) |
| AEC Pipelines, L.P. distribution | (24.3) | (13.1) | - |
| Other | 3.6 | 14.3 | - |
| | 737.2 | 12.1 | 787.1 |
| (Decrease) Increase in Cash | $ (15.1) | $ (31.9) | $ 12.5 |
| Cash, Beginning of Year | $ 44.8 | $ 76.7 | $ 64.2 |
| Cash, End of Year | $ 29.7 | $ 44.8 | $ 76.7 |
| **CASH FLOW FROM OPERATIONS PER COMMON SHARE** | | | |
| Basic | $ 4.26 | $ 4.87 | $ 3.93 |
| Fully diluted | $ 4.06 | $ 4.67 | $ 3.82 |
| ***Supplemental disclosure of cash flow information*** | | | |
| **Interest paid** | **$ 89.0** | **$ 51.0** | **$ 52.2** |
| **Income taxes paid** | **$ 13.2** | **$ 14.7** | **$ 42.0** |

*Tabular amounts in Canadian $ millions, unless otherwise indicated*

## NOTE 1 Summary of Significant Accounting Policies

**The Company organizes its operations into two business groups. Upstream includes the Western Canadian Conventional operations, including the exploration for and production of natural gas and conventional oil, Syncrude, and International. Midstream includes both the Pipelines and Gas Processing operations and the Gas Storage and Hub Services operations.**

### (A) PRINCIPLES OF CONSOLIDATION

The Consolidated Financial Statements include the accounts of Alberta Energy Company Ltd. (the "Company") and its subsidiaries, all of which are wholly owned, except for AEC Pipelines, L.P., which is 70% owned.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called "affiliates") and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships over which the Company has significant influence are accounted for using the equity method.

A listing of major subsidiaries, affiliates, unincorporated joint ventures and partnerships can be found on the inside back cover.

### (B) CAPITAL ASSETS

**Upstream**

*Conventional* The Company accounts for conventional oil and gas properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry.

All costs associated with the acquisition, exploration and development of oil and gas reserves are capitalized in cost centres on a country-by-country basis.

Depletion and depreciation are calculated using the unit-of-production method based on estimated proven reserves, before royalties. For purposes of this calculation, oil is converted to gas on an energy-equivalent basis. All capitalized costs, except as noted, are subject to depletion and depreciation including costs related to unproven properties as well as estimated future costs to be incurred in developing proven reserves. Costs of exploration and land in international cost centres and certain unproved lands in Canada are excluded from costs, subject to depletion, until it is determined whether or not proved reserves are attributable to the properties or impairment has occurred.

Future removal and site restoration costs are estimated and recorded over the estimated life of the reserves.

A ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proven reserves less the cost incurred or estimated to develop those reserves, related production, interest and general and administration costs, and an estimate for restoration costs and applicable taxes. The calculations are based on sales prices and costs at the end of the year.

*Oil Sands* Capital assets associated with surface mineable projects are accumulated, at cost, in separate cost centres. Substantially all of these costs are amortized using the unit-of-production method based on estimated proven developed reserves, applicable to each project.

**Midstream**

Capital assets related to pipelines are carried at cost and depreciated using the straight-line method over their economic life.

Capital assets related to the Company's natural gas liquids extraction plant operations and gas storage facilities are carried at cost and depreciated using the straight-line method over a term of 20 years.

### (C) FOREIGN CURRENCY TRANSLATION

Operations outside Canada are considered to be self-sustaining and use their primary currency for recording substantially all transactions. The accounts of self-sustaining foreign subsidiaries are translated using the current rate method, whereby assets and liabilities are translated at year-end exchange rates, while revenues and expenses are converted using average annual rates. Translation gains and losses relating to these subsidiaries are deferred and included in Shareholders' Equity.

Long-term debt payable in U.S. dollars is translated into Canadian dollars at the year-end exchange rate, with any resulting adjustment amortized using the straight-line method over the remaining life of the debt.

**(D) PROJECT INVESTIGATION COSTS**

Project investigation costs for new business opportunities are charged to earnings as incurred until such time as the commercial viability of the project is established.

**(E) INVENTORIES**

Inventories are valued at the lower of cost or estimated net realizable value.

**(F) INTEREST CAPITALIZATION**

Interest is capitalized during the construction phase of large capital projects.

**(G) HEDGING ACTIVITIES**

Settlement of crude oil and natural gas price swap agreements, which have been arranged as a hedge against commodity price and currency fluctuations, are reflected in product revenues at the time of sale of the related hedged production.

**(H) INCOME TAXES**

Income taxes are recorded using the deferral method of accounting.

**(I) COMPARATIVE FIGURES**

Certain 1997 and 1996 figures have been reclassified for comparative purposes.

## NOTE 2 Acquisition

On October 23, 1998, the Company acquired control of, and in November, acquired all of the issued and outstanding Common Shares of Amber Energy Inc. ("Amber") for consideration of cash and 4.5 million Common Shares. Concurrent with the acquisition, the Company issued, by way of Subscription Receipts, 6.35 million Common Shares for net proceeds of $195.4 million which were used as part of the cash consideration paid for the shares of Amber. Amber was engaged in the exploration and production of oil and natural gas in Canada.

In January 1996, the Company acquired all of the issued and outstanding Common and Preference Shares of Conwest Exploration Company Limited ("Conwest") for consideration of 23.6 million Common Shares and cash. Conwest was engaged primarily in the exploration and production of oil and natural gas and had an investment portfolio and mining and hydroelectric operations. On acquisition, $165 million of non-oil and gas assets of Conwest and an equivalent amount of debt were not consolidated in the financial statements, since the Company intended to dispose of these assets. These assets have been subsequently disposed.

These acquisitions have been accounted for using the purchase method with the results of operations of Amber and Conwest included in the Consolidated Financial Statements from the dates of acquisition.

| | 1998 Amber | 1996 Conwest |
|---|---|---|
| **The fair value of assets acquired is as follows:** | | |
| Non-Cash Working Capital (Deficiency) | **$ 1.7** | $ (0.2) |
| Capital Assets | **833.1** | 1,004.4 |
| Non-Oil and Gas Assets | **-** | 165.0 |
| Deferred Income Taxes | **(7.5)** | (27.2) |
| Other Non-Current Liabilities | **(13.8)** | (21.1) |
| Net assets acquired | **$ 813.5** | $1,120.9 |
| **Financed By:** | | |
| Cash Consideration | **$ 303.2** | $ 365.0 |
| Equity Consideration | **150.0** | 540.4 |
| Long-Term Debt Assumed | **360.3** | 215.5 |
| | **$ 813.5** | $1,120.9 |

## NOTE 3 Dispositions

**AEC Pipelines, L.P.**

On April 9, 1997 AEC Pipelines, L.P., a limited partnership, completed a public offering of Partnership Units for cash proceeds of $301.2 million. A portion of the net proceeds and the issue of additional Partnership Units to the Company were used by the Partnership to acquire from the Company operating crude oil pipeline assets. In addition, the Partnership acquired Subordinated Notes and Non-Voting Shares for $200 million in AEC Express Holdings Ltd., the principal asset of which is a 50% interest in the Express Pipeline System. The Company holds a 70% interest in the Partnership and the minority interest has been reflected in these financial statements.

A dilution gain of $178 million ($1.59 per Common Share–basic) was recorded on completion of the transaction. This gain represents the increase in the Company's share of the accounting value of the Partnership equity resulting from the transaction, and no income tax has been provided as the Company has no plans to dispose of the asset.

**Disposal of assets**

In 1998, the Company sold certain non-core oil and gas properties for proceeds of $25.3 million.

During 1997, the Company disposed of $92.2 million of non-core producing oil and gas properties and other assets. In addition, $102.8 million of oil and gas equipment and storage equipment was sold and subsequently leased under a long-term operating lease agreement.

In 1996, the Company sold certain non-core oil and gas properties for proceeds of $51.5 million and received $15.0 million as a recovery of income taxes related to the discontinued operations of the Forest Products Division, which was sold in 1995.

## NOTE 4 Equity earnings

Midstream includes Equity Earnings from the Company's investments of $4.7 million (1997 - $4.6 million; 1996 – $6.3 million).

## NOTE 5 Interest, net

| | 1998 | 1997 | 1996 |
|---|---|---|---|
| Interest Expense – Long-Term Debt | $ 92.5 | $ 57.7 | $ 61.4 |
| Interest Expense – Other | (1.6) | 1.4 | 0.5 |
| Interest Income | (4.9) | (3.3) | (2.7) |
| | 86.0 | 55.8 | 59.2 |
| Less: | | | |
| Capitalized Interest | 1.3 | 6.9 | 5.8 |
| Interest, Net | $ 84.7 | $ 48.9 | $ 53.4 |

Included in Interest Expense - Other is a $7.1 million foreign exchange gain related to the reduction in the Company's net investment in the Express Pipeline System.

## NOTE 6 Income taxes

The provision for income taxes is as follows:

| | 1998 | 1997 | 1996 |
|---|---|---|---|
| Current | $ (9.3) | $ 7.7 | $ 4.0 |
| Deferred | 47.9 | 67.0 | 70.6 |
| Alberta Royalty Tax Credit | (1.2) | (1.5) | (1.5) |
| Large Corporations Tax | 9.9 | 7.3 | 5.9 |
| Income Taxes | $ 47.3 | $ 80.5 | $ 79.0 |

The following table reconciles income taxes calculated at statutory rates with actual income taxes:

| | 1998 | 1997 | 1996 |
|---|---|---|---|
| Earnings Before Income Taxes | $ 71.7 | $ 280.2 | $ 132.0 |
| Income Taxes at Statutory Rate of 44.6% | 32.0 | 125.0 | 58.9 |
| Effect on Taxes Resulting From: | | | |
| Non-Deductibility of Crown Payments and Depreciation, Depletion and Amortization | 65.1 | 66.2 | 56.5 |
| Non-Deductible Additional Depletion | 3.6 | 26.3 | - |
| Non-Taxable Dilution Gain (Note 3) | - | (79.4) | - |
| Federal Resource Allowance | (52.2) | (56.9) | (41.4) |
| Alberta Royalty Tax Credit | (1.2) | (1.5) | (1.5) |
| Large Corporations Tax | 9.9 | 7.3 | 5.9 |
| Other | (9.9) | (6.5) | 0.6 |
| Income Taxes (Effective rate: 1998 – 66.0%; 1997 – 28.7%; 1996 – 59.8%) | $ 47.3 | $ 80.5 | $ 79.0 |

The Company's U.S. subsidiaries have approximately US$4.5 million of tax losses available which can be applied, with certain restrictions, against future taxable income earned in the U.S. The benefit of these tax losses, which will expire in 2004, has not been recorded.

The amount of capital assets without a tax base is $690.5 million (1997 - $541.0 million). The amount of tax pools available are $2.8 billion (1997 - $1.8 billion).

**NOTE 7 Inventories**

| | 1998 | 1997 |
|---|---|---|
| Product | $ 94.0 | $ 45.8 |
| Parts, Supplies and Other | 45.7 | 27.0 |
| | $ 139.7 | $ 72.8 |

**NOTE 8 Capital Assets**

| | 1998 | | | 1997 | | |
|---|---|---|---|---|---|---|
| | Cost | Accumulated DD&A* | Net | Cost | Accumulated DD&A* | Net |
| **Upstream** | | | | | | |
| Conventional | $ 6,060.7 | $ 2,205.9 | $ 3,854.8 | $ 4,461.8 | $ 1,746.8 | $ 2,715.0 |
| Oil Sands | 613.2 | 187.6 | 425.6 | 544.4 | 171.0 | 373.4 |
| **Midstream** | 1,270.1 | 326.3 | 943.8 | 1,113.8 | 294.4 | 819.4 |
| | $ 7,944.0 | $ 2,719.8 | $ 5,224.2 | $ 6,120.0 | $ 2,212.2 | $ 3,907.8 |

** Depreciation, depletion and amortization*

Included in Midstream is $36.8 million (1997 - $28.1 million) related to cushion gas required to operate the AECO-C storage facility, which is not subject to depletion.

At December 31, 1998, $37.9 million (1997 - $7.0 million; 1996 - $31.9 million) of expenditures in international cost centres and $117.0 million of unproved land in Canada (1997 – nil) were excluded from depletable costs.

The prices used in the ceiling test evaluation of the Company's conventional reserves at December 31, 1998 were as follows:

| | |
|---|---|
| Natural gas: | $ 2.58/thousand cubic feet |
| Crude oil: | $11.74/barrel |
| Natural gas liquids: | $13.50/barrel |
| International crude oil: | $17.44/barrel |

Additional depletion and amortization includes additional depletion on international cost centres of $14.0 million as a result of a ceiling test evaluation based on average prices for the year. Had year-end prices been used, additional depletion would have increased by $13.0 million. In 1997, additional depletion and amortization included $72.4 million on international cost centres as a result of a ceiling test evaluation and $12.5 million of additional amortization of Midstream capital assets.

Depreciation, depletion and amortization includes $49.8 million (1997 - $52.7 million; 1996 - $52.8 million) of depletion related to costs which are not deductible for income tax purposes.

**NOTE 9 Investments and Other Assets**

| | 1998 | 1997 |
|---|---|---|
| Investment in Iroquois Gas Transmission System | $ 19.7 | $ 17.3 |
| Deferred Financing Costs | 27.2 | 3.7 |
| Deferred Foreign Exchange | 21.4 | 7.0 |
| Assets Under Capital Lease | 21.0 | - |
| Other | 6.6 | 19.0 |
| | $ 95.9 | $ 47.0 |

## NOTE 10 Long-Term Debt

| | Note Reference | 1998 | 1997 |
|---|---|---|---|
| **Canadian Dollar Debt** | | | |
| Revolving Credit and Term Loan Borrowings | B | | |
| Notes Payable | | $ 470.8 | $ 526.4 |
| Unsecured Debentures | C | | |
| 9.50%, due February 15, 2000 | | 25.0 | 25.0 |
| 7.60%, due March 15, 2001 | | 50.0 | 50.0 |
| 9.85%, due March 15, 2002 | | 25.0 | 25.0 |
| 8.15%, due July 31, 2003 | | 100.0 | 100.0 |
| 6.60%, due June 30, 2004 | | 50.0 | 50.0 |
| 5.95%, due October 1, 2007 | | 200.0 | - |
| 5.95%, due June 2, 2008 | | 100.0 | - |
| 5.80%, due June 19, 2008 | | 100.0 | - |
| 5.50% / 6.20%, due June 23, 2008 | | 50.0 | - |
| 8.50%, due March 15, 2011 | | 50.0 | 50.0 |
| | | 750.0 | 300.0 |
| **U.S. Dollar Debt** | | | |
| US$238 million Unsecured Senior Notes | D | | |
| 6.99%, due August 29, 2001 | | 61.2 | 57.2 |
| 7.34%, due August 29, 2006 | | 130.1 | 121.5 |
| 6.78%, due August 10, 2008 | | 172.9 | - |
| U.S. Revolving Credit and Term Loan Borrowings | B | | |
| Term loans | | 61.7 | 1.7 |
| | | $ 1,646.7 | $ 1,006.8 |

**(A) MANDATORY FIVE-YEAR DEBT REPAYMENTS**

The minimum annual repayments of long-term debt required over each of the next five years are as follows:

| 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|
| $ - | $ 40.3 | $ 95.9 | $ 25.0 | $ 100.0 |

**(B) REVOLVING CREDIT AND TERM LOAN BORROWINGS**

| Entity | Loan Facility | Currency | $ Utilized |
|---|---|---|---|
| Alberta Energy Company Ltd. | $ 1,375 million | Canadian dollars or U.S. equivalent | $ 455 million |
| AEC Oil Sands Ltd. | 25 million | Canadian dollars or U.S. equivalent | 19 million |
| AEC Oil Sands, L.P. | 25 million | Canadian dollars or U.S. equivalent | nil |
| Amber Energy Inc. | 90 million | Canadian dollars | nil |
| | $ 1,515 million | | $ 474 million |
| Alenco Inc. | $ 50 million | U.S. dollars | $ 40 million |

On a consolidated basis, the Company and its subsidiaries have ten revolving credit and term loan facilities in place totaling $1,515 million Canadian and US$50 million totaling $1,592 million Canadian equivalent at December 31, 1998.

The Company alone has five revolving credit and term loan facilities in place totaling $875 million. The five facilities are fully revolving for 364-day periods with provision for extensions at the option of the lenders and upon notice from the Company. If not extended, two facilities convert to non-revolving reducing loans for terms of 6.5 years, one for a term of 7 years and two for terms of 8 years.

The five loan facilities are unsecured and currently bear interest either at the lenders' rates for Canadian Prime Commercial or U.S. Base Rate loans, or at Bankers' Acceptance rates, or at LIBOR plus applicable margins.

The Company also has a revolving credit facility in the amount of $500 million which was put in place for the acquisition of Amber Energy Inc. and general corporate purposes. This facility matures in October 1999. This facility is unsecured and currently bears interest at either the lenders' rates for Canadian Prime Commercial or U.S. Base Rate loans, or at Bankers' Acceptance rates. At December 31, 1998, $238 million was drawn on this facility. The repayment of this amount is not expected to require the use of working capital during the year and is fully supported by the availability of term loans under the revolving credit and term loan facilities.

The Company's subsidiaries have three unsecured revolving credit and term loan facilities. The facilities are fully revolving for 364-day periods with provisions for extensions at the option of the lender following notice from the subsidiary. If not extended, the facilities convert to non-revolving reducing facilities to be repayable in full in five to eight years. The $90 million loan facility in the name of Amber Energy Inc. is a revolving facility which matures in May 1999.

The subsidiary facilities currently bear interest either at the lender's rates for Canadian Prime Commercial or U.S. Base Rate loans, or at Bankers' Acceptance rates, or at LIBOR plus applicable margins.

Notes payable consist of Bankers' Acceptances and Commercial Paper maturing at various dates with a weighted-average interest rate of 5.51% (1997 – 4.34%). Notes payable shown as long-term debt represent amounts which are not expected to require the use of working capital during the year, and are fully supported by the availability of term loans under the revolving credit and term loan facilities.

**(C) UNSECURED DEBENTURES**

In 1998, under its medium term note program, the Company issued $450 million in unsecured debentures.

**(D) U.S. UNSECURED SENIOR NOTES**

The Company has outstanding, under two separate agreements, Senior Notes in the amount of US$238 million. One agreement consists of two tranches totaling US$125 million. The first tranche in the amount of US$40 million bears interest payable quarterly at 6.99%. The terms of this tranche require principal repayments of US$10 million in August 2000 and US$30 million at maturity in August 2001. The second tranche in the amount of US$85 million bears interest payable quarterly at 7.34% and requires principal repayments of US$28.3 million in August 2004 and August 2005 and US$28.4 million at maturity in August 2006.

The second agreement in the amount of US$113 million bears interest payable quarterly at 6.78% with mandatory annual principal repayments of US$22.6 million commencing in August 2004 and ending August 2008.

## NOTE 11 Indirect Midstream Long-Term Debt

| | Note Reference | 1998 | 1997 |
|---|---|---|---|
| Canadian Dollar Debt | | | |
| Revolving Credit and Term Loan Borrowings | A | | |
| Notes payable | | **18.4** | 2.0 |
| U.S. Dollar Debt | | | |
| U.S. Senior Secured Notes | B | | |
| 6.47% due December 31, 2013 | | **114.6** | - |
| 7.39% due December 31, 2019 | | **191.2** | - |
| Other | | **8.3** | 9.8 |
| | | **332.5** | 11.8 |
| Current Portion of Long-Term Debt | | **1.8** | 1.5 |
| | | **$ 330.7** | 10.3 |

**(A) REVOLVING CREDIT AND TERM LOAN BORROWINGS**

AEC Pipelines, L.P. has an unsecured revolving credit and term loan facility of $50 million which is fully revolving for 364-day periods with provisions for extensions at the option of the lender following notice from the L.P. If not extended, the facility converts to a non-revolving reducing facility to be repayable in full by the end of three years. The facility currently bears interest either at the lender's rates for Canadian Prime Commercial or U.S. Base Rate loans, or at Bankers' Acceptance rates, or at LIBOR plus applicable margins.

**(B) U.S. SENIOR SECURED NOTES**

One of the Company's 50% proportionately consolidated subsidiaries has outstanding US$150 million (AEC share - $75 million) aggregate principal amount of Senior Secured Notes due in 2013, and US$250 million (AEC share - $125 million) aggregate principal amount of Subordinated Secured Notes due in 2019, which are non-recourse to the Company. The notes are secured by the assignment of the accounts receivable of the Express Pipeline System and a floating charge over the assets of the Canadian portion of the Express System.

**(C) MANDATORY FIVE-YEAR DEBT REPAYMENTS**

The minimum annual repayments of Indirect Midstream Long-Term Debt required over each of the next five years are as follows:

| 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|
| $ 1.8 | $ 6.3 | $ 9.9 | $ 13.3 | $ 12.8 |

## NOTE 12 Other Liabilities

| | 1998 | 1997 |
|---|---|---|
| Future Removal and Site Restoration Costs | **$ 61.8** | $ 50.9 |
| Deferred Revenue and Other | **45.1** | 21.7 |
| Obligation Under Capital Lease | **21.0** | - |
| Long-Term Liabilities Related to Syncrude | **6.7** | 6.6 |
| | **$ 134.6** | $ 79.2 |

In December 1998, the Company entered into a capital lease agreement relating to its interest in the Suffield Gas Pipeline, a natural gas pipeline from Suffield, Alberta to Burstall, Saskatchewan. The lease obligation bears interest at a floating rate based on the Bankers' Acceptance rate.

## NOTE 13 Share Capital

Authorized

| | |
|---|---|
| 20,000,000 | First Preferred Shares |
| 20,000,000 | Second Preferred Shares |
| 20,000,000 | Third Preferred Shares |
| Unlimited | Common Shares |
| 5,000,000 | Non-Voting Shares |

| | 1998 Number of Shares | | 1998 Amount | | 1997 Number of Shares | | 1997 Amount | |
|---|---|---|---|---|---|---|---|---|
| **Common Shares** | | | | | | | | |
| Balance, Beginning of Year | | **112,107,871** | | **$ 1,546.0** | | 111,487,101 | | $1,532.0 |
| Issued on Acquisition (Note 2) | | **4,499,921** | | **150.0** | | - | | - |
| Issued for Cash | | | | | | | | |
| Subscription Receipts | **6,350,000** | | **$195.4** | | - | | $ - | |
| Employee Share Option Plan | **1,000,588** | | **22.2** | | 505,686 | | 10.1 | |
| Shareholder Investment Plan | **73,109** | | **2.4** | | 115,084 | | 3.9 | |
| | | **7,423,697** | | **220.0** | | 620,770 | | 14.0 |
| Balance, End of Year | | **124,031,489** | | **$ 1,916.0** | | 112,107,871 | | $1,546.0 |

The Employee Share Option Plan provides for granting to employees of the Company and its subsidiaries options to purchase Common Shares of the Company. Each option granted under the plan expires after seven years and may be exercised in cumulative annual amounts of 25% on or after each of the first four anniversary dates of the grant.

At December 31, 1998, employee share options, exercisable between 1999 and 2005, were outstanding to purchase 9,232,651 (1997 - 7,061,714) Common Shares at prices ranging from $12.04 to $38.15 per share with an average of $27.25 per share.

| | 1998 | 1997 |
|---|---|---|
| Common Shares Under Option, Beginning of Year | **7,061,714** | 4,684,050 |
| Share Options Granted | **3,523,850** | 3,057,850 |
| Share Options Exercised | **(1,000,588)** | (505,686) |
| Share Options Canceled | **(352,325)** | (174,500) |
| Common Shares Under Option, End of Year | **9,232,651** | 7,061,714 |

The number of Common Shares reserved for issuance under the Employee Share Option Plan was 9,429,650 at December 31, 1998 (10,430,238 at December 31, 1997).

**NOTE 14 Financial Instruments**

The Company's financial instruments that are included in the Consolidated Balance Sheet are comprised of cash, accounts receivable, and all current liabilities and long-term borrowings.

**(A) OIL AND GAS PRICE HEDGING**

A total of 7.7 billion cubic feet of produced gas is subject to price swap arrangements for settlement in 1999 and 2000 at an average swap price of $2.97 (Canadian equivalent) per thousand cubic feet.

An affiliate utilizes financial futures contracts as a hedge of inventory. At December 31, 1998, AEC's share of the net open interest was 469,000 barrels of crude oil sold forward. AEC's share of the fair value of these contracts is $3.5 million (Canadian equivalent) at December 31, 1998. Gains and losses on hedge positions are deferred to future periods in which inventory will be sold.

The affiliate has entered into a hedge arrangement to sell US$2.5 million (AEC share) in equal daily amounts at the prevailing daily rates expiring in January 1999. The affiliate also has a forward purchase agreement to buy US$4.3 million (AEC share) that has a fair value loss of $0.1 million at December 31, 1998. These positions are hedges of the affiliate's exposure to net U.S. dollar receivables, and gains are therefore deferred to the future periods in which the receivables are to be realized.

**(B) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES**

The fair values of financial instruments that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year-end.

| | 1998 | | 1997 | |
|---|---|---|---|---|
| | **Balance Sheet Amount** | **Fair Value** | **Balance Sheet Amount** | **Fair Value** |
| Long-Term Debt | **$ 1,646.7** | **$ 1,694.3** | $ 1,006.8 | $ 1,047.7 |
| Indirect Midstream Long-Term Debt | **330.7** | **341.7** | 10.3 | 10.3 |

**(C) CREDIT RISK**

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. All natural gas swap agreements are with major financial institutions in Canada and the United States.

**(D) INTEREST RATE RISK**

At December 31, 1998, the increase or decrease in Net Earnings for each 1% change in interest rates on floating rate debt amounts to $3.2 million (1997 - $3.1 million).

**(E) INTEREST RATE AND FOREIGN CURRENCY SWAPS**

The Company has outstanding interest rate swaps, which were acquired with Amber, on a total of US$70 million of long-term debt. These swaps convert floating rate interest into fixed rate interest until January 2003. At December 31, 1998 these swaps result in an unrealized settlement liability of $1.5 million which was provided for at the time of purchase.

The Company also has in place two foreign exchange contracts to sell U.S. dollars in exchange for Canadian dollars. One contract is for $2 million/month until November 1999 and the other is for $2 million/month until December 2000. These contracts were acquired with the purchase of Amber. At December 31, 1998, these contracts have an unrealized settlement loss of $9.9 million which was provided for at the time of the purchase.

At December 31, 1997, an affiliate had an interest rate swap outstanding with an unrealized settlement liability of US$11.2 million (AEC share). On February 6, 1998, as part of the completion of non-recourse project debt financing of the affiliate, the swap was settled for US$14.6 million (AEC share) and this amount is being amortized over the term of the project debt.

**NOTE 15 Supplementary Information**

**(A) INVESTMENTS PROPORTIONATELY CONSOLIDATED**

The Company conducts a substantial portion of its oil and gas activity through unincorporated joint ventures which are accounted for using the proportionate consolidation method. In addition, certain investments in Midstream are proportionately consolidated. These include the 50%-owned Express Pipeline System, the 50%-owned Marquest Energy Group, the 49.995% owned Pan-Alberta Resources Inc., the 35%-owned Empress Straddle Plant and the 33%-owned Alberta Ethane Gathering System. Included in the Company's accounts are the following amounts related to these activities:

| | 1998 | 1997 |
|---|---|---|
| Current Assets | $ 58.8 | $ 77.5 |
| Total Assets | 622.1 | 547.4 |
| Current Liabilities | 38.1 | 73.2 |
| Total Liabilities | 331.0 | 110.1 |
| Revenues | 340.0 | 386.8 |
| Net Earnings (Loss) | (14.0) | 12.7 |
| Cash Flow From Operations | (8.5) | 21.2 |
| Financing Activities | 42.5 | 100.2 |
| Investing Activities | 34.0 | 117.8 |

**(B) PENSION PLANS**

The Company has both a defined benefit pension plan and a defined contribution plan which cover substantially all employees. The defined benefit pension plan provides pension benefits upon retirement based on length of service and final average earnings. Defined contribution benefits are determined by the value of contributions and the return on investment of these contributions.

The cost of pension benefits earned by employees is determined using the projected unit credit method and is expensed as services are rendered. This cost is actuarially determined and reflects management's best estimate of the pension plan's expected investment yields and the expected salary escalation, mortality rates, termination dates and retirement ages of pension plan members. The plan is funded as actuarially determined in accordance with regulatory requirements through contributions to a trust fund. The costs of defined contribution pension benefits are based on a percentage of salary.

The cumulative difference between the amounts funded and expensed is reflected as a deferred asset in the Consolidated Balance Sheet.

At December 31, 1998, the market value of defined benefit pension fund assets was $73.0 million (1997 - $65.4 million) and the accrued pension liability, as estimated by the Company's actuaries, was $72.6 million (1997 - $64.9 million).

In addition, one of the Company's unincorporated joint ventures has a defined benefit pension plan. At December 31, 1998, the market value of the Company's share of pension fund assets was $88.6 million (1997 - $80.3 million) and the Company's share of accrued pension liability, as estimated by the joint venture's actuaries, was $80.0 million (1997 - $73.7 million).

**(C) RELATED PARTY TRANSACTIONS**

During the year, the Company sold approximately $17.5 million (1997 - $30.4 million) of natural gas and $26.8 million (1997 - $ 41.6 million) of crude oil to affiliates at market prices, $3.1 million of which is included in accounts receivable at year-end (1997 - $6.8 million).

**(D) NET CHANGE IN NON-CASH WORKING CAPITAL**

| Source / (Use) | 1998 | 1997 | 1996 |
|---|---|---|---|
| Operating Activities | | | |
| Accounts Receivable and Accrued Revenue | $ (9.7) | $ (121.1) | $ (29.9) |
| Inventories | (62.3) | (36.0) | (7.7) |
| Accounts Payable and Accrued Liabilities | 12.4 | 72.3 | (13.2) |
| | $ (59.6) | $ (84.8) | $ (50.8) |
| Investing Activities | | | |
| Accounts Payable and Accrued Liabilities | $ (9.5) | $ (9.9) | $ 80.7 |

## NOTE 16 United States Accounting Principles and Reporting

**Tabular amounts in Canadian $ millions, unless otherwise indicated.**

The financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles. They differ from those generally accepted in the United States in the following respects:

**(A) FULL COST ACCOUNTING**

Under Canadian Generally Accepted Accounting Principles (GAAP), a ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proven reserves less the cost incurred or estimated to develop those reserves, related production, interest and general and administration costs, and an estimate for restoration costs and applicable taxes.

Under the full cost method of accounting in the United States, costs accumulated in each cost centre are limited to an amount equal to the present value, discounted at 10%, of the estimated future net operating revenues from proven reserves, net of restoration costs and income taxes.

**(B) INCOME TAXES**

Under Canadian GAAP, the Company provides for potential future taxes using the deferred credit method under which tax provisions are established using tax rates and regulations applicable in the year the provision is recorded. These remain unchanged despite subsequent changes in rates and regulations.

In the United States, Statement of Financial Accounting Standards No. 109 (FAS 109), "Accounting for Income Taxes," requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. In estimating future tax consequences, FAS 109 generally considers all expected events including enacted changes in laws or rates.

**(C) FOREIGN CURRENCY TRANSLATION**

Under Canadian GAAP, long-term debt in foreign currencies was translated at the rate of exchange in effect at the end of the year. Unrealized exchange gains and losses arising on translation were deferred and amortized over the remaining terms of the debt. U.S. GAAP requires that such gains and losses be reflected in the period in which they arise. Gains and losses on the change in the Company's net investments in foreign operations are not included in income under U.S. GAAP.

**(D) EARNINGS PER SHARE**

Under Canadian GAAP, the fully diluted earnings related to the number of shares issued under employee option plans is determined using the average exercise price for all options outstanding. Under U.S. GAAP, the treasury method is used in the determination of the fully diluted earnings per share.

**(E) UNITED STATES EARNINGS**

If the Consolidated Financial Statements had been prepared in accordance with GAAP in the United States the following adjustments would be required:

| | 1998 | 1997 | 1996 |
|---|---|---|---|
| Net Earnings According to Canadian GAAP | **$ 24.4** | $ 199.7 | $ 68.0 |
| Impact of U.S. Accounting Principles: | | | |
| Foreign Exchange | **(21.8)** | (7.0) | - |
| Additional Depletion (1) | **(277.2)** | - | - |
| Income Taxes | **132.9** | 1.3 | 6.1 |
| Net Earnings (Loss) According to U.S. GAAP | **$ (141.7)** | $ 194.0 | $ 74.1 |
| Earnings (Loss) per share | | | |
| Basic | **$ (1.23)** | $ 1.73 | $ 0.71 |
| Fully diluted | **$ (1.23)** | $ 1.73 | $ 0.71 |

*(1) In 1998 the Company recorded additional depletion of $277.2 million that reduced the carrying amount of its conventional oil and gas capital assets and related income tax savings of $123.7 million as a result of applying the U.S. GAAP ceiling test rules. The additional depletion is mainly due to the decline in oil prices and the long life of the Company's reserve base.*

Not in 96 97's annuals

**Comprehensive Income**

| | 1998 | 1997 | 1996 |
|---|---|---|---|
| Net Earnings according to U.S. GAAP | **$ (141.7)** | $ 194.0 | $ 74.1 |
| Foreign currency translation adjustment | **21.6** | 14.4 | 2.0 |
| Comprehensive income | **$ (120.1)** | $ 208.4 | $ 76.1 |

At December 31, 1998, the 10% discounted amount of the Company's Western Canadian Conventional oil and gas reserves is $3,168 million.

The adjustments under U.S. GAAP would result in changes to the Consolidated Balance Sheet of the Company as follows:

| | As at December 31, 1998 | | As at December 31, 1997 | |
|---|---|---|---|---|
| | As Reported | U.S. GAAP | As Reported | U.S. GAAP |
| **Assets** | | | | |
| Current Assets | **$ 539.6** | **$ 539.6** | $ 443.1 | $ 443.1 |
| Capital Assets | **5,224.2** | **5,407.9** | 3,907.8 | 4,225.0 |
| Investments and Other Assets | **95.9** | **74.1** | 47.0 | 40.0 |
| | **$ 5,859.7** | **$ 6,021.6** | $ 4,397.9 | $4,708.1 |
| **Liabilities and Shareholders' Equity** | | | | |
| Current Liabilities | **$ 428.8** | **$ 428.8** | $ 388.3 | $ 388.3 |
| Long-Term Debt | **1,646.7** | **1,646.7** | 1,006.8 | 1,006.8 |
| Indirect Midstream Long-Term Debt | **330.7** | **330.7** | 10.3 | 10.3 |
| Other Liabilities | **134.6** | **134.6** | 79.2 | 79.2 |
| Deferred Income Taxes | **630.7** | **988.0** | 585.4 | 929.5 |
| Minority Interest | **108.3** | **108.3** | 114.2 | 114.2 |
| Shareholders' Equity | **2,579.9** (195.40) | **2,384.5** | 2,213.7 | 2,179.8 |
| | **$ 5,859.7** | **$ 6,021.6** | $ 4,397.9 | $4,708.1 |

## NOTE 17 Commitments

The Company has committed to certain payments over the next five years as follows:

| | 1999 | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|---|
| Natural Gas Transportation | $ 87.2 | $ 73.5 | $ 65.6 | $ 50.0 | $ 37.7 |
| Equipment Operating Leases | 12.3 | 13.5 | 13.5 | 13.5 | 13.5 |
| Space Rental | 6.4 | 6.3 | 6.1 | 6.1 | 5.1 |
| Capital Lease | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| Total | $ 107.1 | $ 94.5 | $ 86.4 | $ 70.8 | $ 57.5 |

## NOTE 18 Uncertainty due to the Year 2000

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using Year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000 and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect the Company's ability to conduct normal business operations. It is not possible to be certain that all aspects of the Year 2000 Issue affecting the Company, including those related to efforts of customers, suppliers, or other third parties, will be fully resolved.

**NOTE 19 Segmented Information**

The Company is managed using five operating segments which have been determined based on the nature of the products produced or services provided and the location of the operations. Upstream includes the Western Canadian Conventional operations, including the exploration for and production of natural gas and conventional oil, Syncrude, and International. Midstream includes both the Pipelines and Gas Processing segment and the Gas Storage and Hub Services operations.

**(A) RESULTS OF OPERATIONS**

**UPSTREAM**

| | Western Canadian Conventional | | | Syncrude | | | International | | | Total Upstream | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ($ millions) | 1998 | 1997 | 1996 | 1998 | 1997 | 1996 | 1998 | 1997 | 1996 | 1998 | 1997 | 1996 |
| Revenue | $ 1,269.1 | $1,032.6 | $ 790.8 | $ 221.6 | $ 295.9 | $ 266.5 | $ 14.5 | $ 16.2 | $ 12.3 | $1,505.2 | $1,344.7 | $ 1,069.6 |
| Royalties | 100.4 | 106.2 | 79.0 | (0.3) | 28.0 | 56.3 | 1.7 | 1.9 | 1.7 | 101.8 | 136.1 | 137.0 |
| Net Revenue | 1,168.7 | 926.4 | 711.8 | 221.9 | 267.9 | 210.2 | 12.8 | 14.3 | 10.6 | 1,403.4 | 1,208.6 | 932.6 |
| Operating Costs | 175.5 | 149.2 | 123.4 | 143.4 | 143.1 | 141.9 | 19.6 | 14.3 | 11.2 | 338.5 | 306.6 | 276.5 |
| Cost of Product Purchased | 574.4 | 378.2 | 246.4 | – | – | – | – | – | – | 574.4 | 378.2 | 246.4 |
| Operating Cash Flow | 418.8 | 399.0 | 342.0 | 78.5 | 124.8 | 68.3 | (6.8) | – | (0.6) | 490.5 | 523.8 | 409.7 |
| DD&A | 260.8 | 233.1 | 183.7 | 17.0 | 20.9 | 16.6 | 7.9 | 6.4 | 5.2 | 285.7 | 260.4 | 205.5 |
| DD&A – Acquisitions | 49.8 | 52.7 | 52.8 | – | – | – | – | – | – | 49.8 | 52.7 | 52.8 |
| Additional DD&A | – | – | – | – | – | – | 14.0 | 72.4 | – | 14.0 | 72.4 | – |
| Segment Income | $ 108.2 | $ 113.2 | $ 105.5 | $ 61.5 | $ 103.9 | $ 51.7 | $ (28.7) | $ (78.8) | $ (5.8) | $ 141.0 | $ 138.3 | $ 151.4 |
| Less: Corporate costs | | | | | | | | | | | | |
| General and administrative | | | | | | | | | | 23.3 | 20.9 | 28.1 |
| Corporate DD&A | | | | | | | | | | 7.8 | 7.1 | 4.3 |
| Interest, net | | | | | | | | | | 56.5 | 28.5 | 30.3 |
| Income taxes | | | | | | | | | | 37.2 | 79.8 | 60.9 |
| Net Earnings | | | | | | | | | | $ 16.2 | $ 2.0 | $ 27.8 |

**MIDSTREAM**

| | Pipelines and Gas Processing | | | Gas Storage & Hub Services | | | Total Midstream | | | Consolidated Total | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1998 | 1997 | 1996 | 1998 | 1997 | 1996 | 1998 | 1997 | 1996 | 1998 | 1997 | 1996 |
| Revenue | $ 434.6 | $ 482.5 | $ 164.3 | $ 71.9 | $ 25.8 | $ 25.2 | $ 506.5 | $ 508.3 | $ 189.5 | $ 2,011.7 | $ 1,853.0 | $1,259.1 |
| Royalties | – | – | – | – | – | – | – | – | – | 101.8 | 136.1 | 137.0 |
| Net Revenue | 434.6 | 482.5 | 164.3 | 71.9 | 25.8 | 25.2 | 506.5 | 508.3 | 189.5 | 1,909.9 | 1,716.9 | 1,122.1 |
| Operating Costs | 136.0 | 131.3 | 85.9 | 14.3 | 12.6 | 9.7 | 150.3 | 143.9 | 95.6 | 488.8 | 450.5 | 372.1 |
| Cost of Product Purchased | 207.6 | 252.8 | – | 34.3 | – | – | 241.9 | 252.8 | – | 816.3 | 631.0 | 246.4 |
| Operating Cash Flow | 91.0 | 98.4 | 78.4 | 23.3 | 13.2 | 15.5 | 114.3 | 111.6 | 93.9 | 604.8 | 635.4 | 503.6 |
| DD&A | 36.0 | 28.3 | 15.9 | 5.2 | 7.0 | 6.5 | 41.2 | 35.3 | 22.4 | 326.9 | 295.7 | 227.9 |
| DD&A – Acquisitions | – | – | – | – | – | – | – | – | – | 49.8 | 52.7 | 52.8 |
| Additional DD&A | – | 12.5 | – | – | – | – | – | 12.5 | – | 14.0 | 84.9 | – |
| Dilution Gain | – | – | – | – | – | – | – | 178.0 | – | – | 178.0 | – |
| Segment Income | $ 55.0 | $ 57.6 | $ 62.5 | $ 18.1 | $ 6.2 | $ 9.0 | $ 73.1 | $ 241.8 | $ 71.5 | $ 214.1 | $ 380.1 | $ 222.9 |
| Less: Corporate costs | | | | | | | | | | | | |
| General and administrative | | | | | | | 7.1 | 7.2 | 4.3 | 30.4 | 28.1 | 32.4 |
| Corporate DD&A | | | | | | | 1.1 | 1.0 | 0.8 | 8.9 | 8.1 | 5.1 |
| Interest, net | | | | | | | 28.2 | 20.4 | 23.1 | 84.7 | 48.9 | 53.4 |
| Income taxes | | | | | | | 10.1 | 0.7 | 18.1 | 47.3 | 80.5 | 79.0 |
| Minority interest | | | | | | | 18.4 | 14.8 | – | 18.4 | 14.8 | – |
| Net Earnings | | | | | | | $ 8.2 | $ 197.7 | $ 25.2 | $ 24.4 | $ 199.7 | $ 53.0 |

**(B) CAPITAL INVESTMENT**

| | 1998 | 1997 |
|---|---|---|
| Upstream | | |
| Western Canadian Conventional | **$ 609.8** | $ 669.4 |
| Syncrude | **68.3** | 48.8 |
| International | **64.7** | 48.3 |
| Midstream | | |
| Pipelines and Gas Processing | **72.4** | 157.1 |
| Gas Storage and Hub Services | **43.2** | 40.2 |
| Other | **24.9** | 20.6 |
| Total (1) | **$ 883.3** | $ 984.4 |

*(1) Excludes Amber acquisition of $813.5 million (Note 2)*

**(C) GEOGRAPHIC INFORMATION**

Substantially all of the Company's revenues are generated in Canada, with the exception of the International segment, which is based in Argentina and $49.1 million which relates to the Express Pipeline System for shipments within the United States (1997 - $34.9 million).

The International segment capital assets located outside of Canada are located primarily in Argentina and Australia. Pipelines and Gas Processing includes assets in the United States related to the Express Pipeline System of $388.7 million (1997 - $352.5 million).

**(D) IDENTIFIABLE ASSETS**

| | 1998 | 1997 |
|---|---|---|
| Upstream | | |
| Western Canadian Conventional | **$4,111.6** | $2,936.0 |
| Syncrude | **474.6** | 436.1 |
| International | **99.8** | 47.4 |
| Midstream | | |
| Pipelines and Gas Processing | **970.7** | 842.0 |
| Gas Storage and Hub Services | **203.0** | 136.4 |
| | **$5,859.7** | $4,397.9 |

**(E) WESTERN CANADIAN CONVENTIONAL PRODUCT INFORMATION**

| | Gas and NGLs | | | Oil | | |
|---|---|---|---|---|---|---|
| | 1998 | 1997 | 1996 | 1998 | 1997 | 1996 |
| Gross Revenue | **$1,158.3** | $ 857.5 | $ 634.6 | **$ 110.8** | $ 175.1 | $ 156.2 |
| Royalties | **85.0** | 75.0 | 48.5 | **15.4** | 31.2 | 30.5 |
| Net Revenue | **1,073.3** | 782.5 | 586.1 | **95.4** | 143.9 | 125.7 |
| Operating Costs | **134.6** | 98.9 | 89.9 | **40.9** | 50.3 | 33.5 |
| Cost of Product Purchased | **574.4** | 378.2 | 246.4 | **-** | - | - |
| Operating Cash Flow | **$ 364.3** | $ 305.4 | $ 249.8 | **$ 54.5** | $ 93.6 | $ 92.2 |

# Supplemental Information (Unaudited)

**Alberta Energy Company Ltd.**

**FINANCIAL STATISTICS**

| Year ended December 31 | Year | Q4 | Q3 | Q2 | 1998 Q1 | 1997 | 1996 | 1995 | 1994 |
|---|---|---|---|---|---|---|---|---|---|
| Net Earnings ($ millions) (1) | 24.4 | 7.9 | 9.0 | 5.3 | 2.2 | 21.7 | 68.0 | 110.2 | 100.5 |
| Per share ($) Basic | 0.21 | 0.06 | 0.08 | 0.05 | 0.02 | 0.19 | 0.65 | 1.47 | 1.36 |
| Fully diluted | 0.21 | 0.06 | 0.08 | 0.05 | 0.02 | 0.23 | 0.65 | 1.44 | 1.34 |
| Cash Flow From Operations ($ millions) | 488.5 | 169.3 | 110.8 | 99.9 | 108.5 | 544.7 | 411.9 | 270.7 | 294.8 |
| Per share ($) Basic | 4.26 | 1.43 | 0.98 | 0.88 | 0.97 | 4.87 | 3.93 | 3.61 | 4.07 |
| Fully diluted | 4.06 | 1.34 | 0.94 | 0.86 | 0.92 | 4.67 | 3.82 | 3.51 | 3.88 |
| **Shares** | | | | | | | | | |
| Common Shares Outstanding (millions) | 124.0 | 124.0 | 113.0 | 112.8 | 112.6 | 112.1 | 111.5 | 75.5 | 74.5 |
| Average Common Shares Outstanding (millions) | 114.8 | 114.8 | 112.7 | 112.5 | 112.3 | 111.9 | 104.9 | 75.0 | 71.7 |
| Price Range ($ per share) | | | | | | | | | |
| **TSE** | | | | | | | | | |
| High | 39.00 | 39.00 | 36.95 | 35.85 | 36.30 | 35.50 | 33.25 | 23.13 | 22.75 |
| Low | 25.75 | 31.55 | 28.00 | 29.75 | 25.75 | 26.00 | 21.75 | 16.38 | 17.50 |
| Close | 33.00 | 33.00 | 34.00 | 34.50 | 35.50 | 27.75 | 32.70 | 21.88 | 17.88 |
| **NYSE – US$** | | | | | | | | | |
| High | 26.25 | 26.25 | 24.63 | 25.13 | 25.14 | 25.88 | 24.13 | 16.75 | – |
| Low | 17.38 | 20.63 | 17.38 | 20.11 | 18.02 | 18.25 | 16.00 | 15.00 | – |
| Close | 21.50 | 21.50 | 22.03 | 23.50 | 24.15 | 19.38 | 24.00 | 16.00 | – |
| Share Volume Traded (millions) | 67.7 | 18.7 | 14.2 | 12.6 | 22.2 | 81.2 | 71.7 | 42.3 | 48.5 |
| **Ratios** | | | | | | | | | |
| Debt-to-Capitalization | | | | | | | | | |
| Corporate (2) | 38:62 | | | | | 29:71 | 32:68 | 25:75 | 35:65 |
| Upstream | 36:64 | | | | | 20:80 | 16:84 | 13:87 | 21:79 |
| Midstream | 60:40 | | | | | 60:40 | 89:11 | 64:36 | 64:36 |
| Debt-to-Cash Flow | | | | | | | | | |
| Upstream (3) | 2.0x | | | | | 1.1x | 1.0x | 0.8x | 1.2x |
| Interest Coverage (4) | 7.0x | | | | | 12.4x | 8.8x | 9.8x | 7.0x |
| Dividend ($ per Common Share) | 0.40 | | | | | 0.40 | 0.40 | 0.40 | 0.40 |

*(1) 1997 net earnings excludes a dilution gain on the sale of AEC Pipelines, L.P. of $178.0 million ($1.59 per share-basic; $1.50 per share - fully diluted)*

*(2) Corporate debt-to-capitalization excludes indirect midstream debt and related capitalization*

*(3) Upstream debt-to-cash flow excludes Amber-related debt of $468 million and two months Cash Flow of $11 million*

*(4) Calculated as operating cash flow less G&A divided by interest*

# Supplemental Information (Unaudited)

**Alberta Energy Company Ltd.**

**UPSTREAM CONSOLIDATED BALANCE SHEET**
**($ millions) as at December 31**

| | 1998 | 1997 |
|---|---|---|
| Assets | | |
| Current assets | $ 386.6 | $ 305.4 |
| Capital assets | 4,280.3 | 3,088.4 |
| Investments and other assets | 19.1 | 25.7 |
| | $ 4,686.0 | $ 3,419.5 |
| Liabilities | | |
| Current liabilities | $ 323.2 | $ 265.8 |
| Long-term debt | 1,355.4 | 519.4 |
| Deferred income taxes & other liabilities | 694.7 | 623.2 |
| | 2,373.3 | 1,408.4 |
| Capital Employed | 2,312.7 | 2,011.1 |
| | $ 4,686.0 | $ 3,419.5 |

*Note: Includes allocation of Corporate Assets and Liabilities*

**UPSTREAM CONSOLIDATED STATEMENT OF OPERATING AND INVESTING ACTIVITIES**
**($ millions) year ended December 31**

| | 1998 | 1997 | 1996 |
|---|---|---|---|
| Operating Activities | | | |
| Net earnings from continuing operations | $ 16.2 | $ 2.0 | $ 27.8 |
| Depreciation, depletion and amortization | 343.3 | 320.2 | 262.6 |
| Additional depletion and amortization | 14.0 | 72.4 | – |
| Deferred income taxes | 41.4 | 74.6 | 59.9 |
| Other | 2.3 | (1.0) | 1.5 |
| Cash flow from operations | 417.2 | 468.2 | 351.8 |
| Investing Activities | | | |
| Acquisition | (303.2) | – | (365.0) |
| Capital investment | (767.7) | (780.4) | (508.3) |
| Proceeds on disposal of assets | 25.3 | 149.5 | 18.9 |
| | $ (1,045.6) | $ (630.9) | $ (854.4) |
| Cash Flow from Operations per Common Share | | | |
| Basic | $ 3.64 | $ 4.19 | $ 3.36 |
| Fully diluted | $ 3.47 | $ 4.01 | $ 3.26 |

# Supplemental Information (Unaudited)

**Alberta Energy Company Ltd.**

**MIDSTREAM CONSOLIDATED BALANCE SHEET**
**($ millions) as at December 31**

| | 1998 | 1997 |
|---|---|---|
| Assets | | |
| Current assets | $ 153.0 | $ 137.7 |
| Capital assets | 943.9 | 819.4 |
| Investments and other assets | 76.8 | 21.3 |
| | $ 1,173.7 | $ 978.4 |
| Liabilities | | |
| Current liabilities | $ 105.6 | $ 122.5 |
| Long-term debt | 291.3 | 487.4 |
| Indirect midstream long-term debt | 330.7 | 10.3 |
| Deferred income taxes & other liabilities | 70.6 | 41.4 |
| Minority interest | 108.3 | 114.2 |
| | 906.5 | 775.8 |
| Capital Employed | 267.2 | 202.6 |
| | $ 1,173.7 | $ 978.4 |

*Note: Includes allocation of Corporate Assets and Liabilities*

**MIDSTREAM CONSOLIDATED STATEMENT OF OPERATING AND INVESTING ACTIVITIES**
**($ millions) year ended December 31**

| | 1998 | 1997 | 1996 |
|---|---|---|---|
| Operating Activities | | | |
| Net earnings from continuing operations | $ 8.2 | $ 197.7 | $ 25.2 |
| Depreciation, depletion and amortization | 42.3 | 36.3 | 23.2 |
| Additional depletion and amortization | – | 12.5 | – |
| Deferred income taxes | 6.5 | (6.8) | 10.7 |
| Dilution gain | – | (178.0) | – |
| Minority interest | 18.4 | 14.8 | – |
| Other | (4.1) | – | 1.0 |
| Cash flow from operations | 71.3 | 76.5 | 60.1 |
| Investing Activities | | | |
| Capital investment – Express Pipeline System | (25.8) | (120.6) | (348.7) |
| Capital investment – other Midstream | (89.8) | (83.4) | (51.0) |
| Proceeds on disposal of assets | – | 45.5 | 32.6 |
| | $ (115.6) | $ (158.5) | $ (367.1) |
| Cash Flow from Operations per Common Share | | | |
| Basic | $ 0.62 | $ 0.68 | $ 0.57 |
| Fully Diluted | $ 0.59 | $ 0.66 | $ 0.56 |

# Supplemental Information (Unaudited)

**Alberta Energy Company Ltd.**

| **OIL AND GAS OPERATING STATISTICS** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **SALES** | | | | | **1998** | | | | |
| **Years Ended December 31** | **Year** | **Q4** | **Q3** | **Q2** | **Q1** | **1997** | **1996** | **1995** | **1994** |
| Produced Gas (million cubic feet/day) | **714** | **912** | **575** | **591** | **778** | 575 | 515 | 320 | 345 |
| Oil and Natural Gas Liquids (barrels/day) | | | | | | | | | |
| Canada | | | | | | | | | |
| Syncrude | **28,953** | **31,005** | **27,937** | **32,368** | **24,440** | 28,447 | 27,596 | 27,823 | 26,282 |
| Conventional | **23,027** | **29,951** | **19,470** | **20,489** | **22,152** | 23,954 | 19,507 | 11,549 | 9,267 |
| Natural Gas Liquids | **5,877** | **6,351** | **5,218** | **5,456** | **6,490** | 4,856 | 4,811 | 1,691 | 1,011 |
| Total Canada | **57,857** | **67,307** | **52,625** | **58,313** | **53,082** | 57,257 | 51,914 | 41,063 | 36,560 |
| International | **2,217** | **2,165** | **2,161** | **2,611** | **1,927** | 1,683 | 1,241 | 1,090 | 260 |
| Total | **60,074** | **69,472** | **54,786** | **60,924** | **55,009** | 58,940 | 53,155 | 42,153 | 36,820 |
| **PER-UNIT RESULTS (CANADA)** | | | | | | | | | |
| Produced Gas ($/thousand cubic feet) | | | | | | | | | |
| Price | **2.04** | **2.35** | **1.93** | **1.83** | **1.91** | 2.04 | 1.77 | 1.40 | 1.88 |
| Royalties | **0.29** | **0.30** | **0.17** | **0.32** | **0.34** | 0.31 | 0.20 | 0.13 | 0.25 |
| Operating costs | **0.42** | **0.44** | **0.36** | **0.47** | **0.41** | 0.40 | 0.43 | 0.34 | 0.37 |
| Netback | **1.33** | **1.61** | **1.40** | **1.04** | **1.16** | 1.33 | 1.14 | 0.93 | 1.26 |
| Conventional Oil ($/barrel) | | | | | | | | | |
| Price | **13.13** | **13.61** | **15.57** | **11.44** | **11.86** | 19.99 | 21.80 | 20.54 | 18.09 |
| Royalties | **1.82** | **1.73** | **1.41** | **2.13** | **2.04** | 3.58 | 4.28 | 3.48 | 2.63 |
| Operating costs | **4.87** | **4.66** | **4.50** | **4.39** | **5.94** | 5.74 | 4.69 | 4.15 | 4.77 |
| Netback | **6.44** | **7.22** | **9.66** | **4.92** | **3.88** | 10.67 | 12.83 | 12.91 | 10.69 |
| Natural Gas Liquids ($/barrel) | | | | | | | | | |
| Price | **16.86** | **14.00** | **13.22** | **19.90** | **20.15** | 23.97 | 23.95 | 15.74 | 15.05 |
| Royalties | **4.52** | **3.51** | **5.02** | **4.45** | **5.17** | 6.11 | 6.70 | 5.25 | 3.98 |
| Netback | **12.34** | **10.49** | **8.20** | **15.45** | **14.98** | 17.86 | 17.25 | 10.49 | 11.07 |
| Syncrude ($/barrel) | | | | | | | | | |
| Price, Net of Tariff | **20.46** | **19.19** | **20.73** | **20.47** | **21.76** | 27.80 | 25.68 | 23.69 | 21.76 |
| Gross Overriding Royalty | **0.51** | **0.10** | **0.51** | **0.71** | **0.74** | 0.69 | 0.71 | 0.60 | 0.56 |
| Royalties | **(0.03)** | **–** | **–** | **(0.09)** | **–** | 2.70 | 5.58 | 3.02 | 1.03 |
| Cash Operating Costs | **13.67** | **11.89** | **13.02** | **11.91** | **19.10** | 13.82 | 13.71 | 13.70 | 14.99 |
| Netback | **7.33** | **7.40** | **8.22** | **9.36** | **3.40** | 11.97 | 7.10 | 7.57 | 6.30 |

# Supplemental Information (Unaudited)

**Alberta Energy Company Ltd.**

**GAS PRODUCTION BY BUSINESS UNIT**

| Years Ended December 31 (million cubic feet/day) | Forecast 1999 | 1998 | 1997 | 1996 | 1995 | 1994 |
|---|---|---|---|---|---|---|
| AEC East | 530 | **389** | 306 | 276 | 276 | 273 |
| AEC West | 350 | **300** | 263 | 229 | 80 | 68 |
| Cushion Gas From Storage | – | **19** | 19 | – | – | 11 |
| Total Field Capability | 880 | **708** | 588 | 505 | 356 | 352 |
| Storage Withdrawal (Injection) | 20 | **6** | (13) | 10 | (36) | (7) |
| Total Produced Gas Sales | 900 | **714** | 575 | 515 | 320 | 345 |

**PRODUCED GAS SALES BY CONTRACT**
**(million cubic feet/day)**

| | | | | | | |
|---|---|---|---|---|---|---|
| TransCanada Gas Services | 117 | **87** | 84 | 85 | 111 | 146 |
| Pan-Alberta Gas | 119 | **92** | 88 | 60 | 31 | 38 |
| ProGas | 155 | **117** | 89 | 50 | 22 | 11 |
| Long-Term Direct | 97 | **113** | 136 | 110 | 90 | 72 |
| Other | 412 | **305** | 178 | 210 | 66 | 78 |
| Total | 900 | **714** | 575 | 515 | 320 | 345 |

**PURCHASED GAS TRANSACTIONS**

| | | | | | | |
|---|---|---|---|---|---|---|
| (million cubic feet/day) | 588 | **752** | 569 | 532 | 308 | 110 |

**OIL AND NGL SALES BY BUSINESS UNIT**
**(barrels/day)**

| | | | | | | |
|---|---|---|---|---|---|---|
| AEC Syncrude | 31,000 | **28,953** | 28,447 | 27,596 | 27,823 | 26,282 |
| AEC East | 28,000 | **16,575** | 17,389 | 12,742 | 10,751 | 8,389 |
| AEC West | 11,000 | **12,329** | 11,421 | 11,576 | 2,489 | 1,889 |
| AEC International | 2,000 | **2,217** | 1,683 | 1,241 | 1,090 | 260 |
| Total | 72,000 | **60,074** | 58,940 | 53,155 | 42,153 | 36,820 |

# Supplemental Information (Unaudited)

**Alberta Energy Company Ltd.**

**RESERVES RECONCILIATION**

| (before royalties) | Natural Gas (billion cubic feet) Prov. | Prob. | Total | Conventional Oil & NGLs (million barrels) Prov. | Prob. | Total | Syncrude (million barrels) Prov. | Prob. | Total | Argentina (million barrels) Prov. | Prob. | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1996** | | | | | | | | | | | | |
| Balance at December 31,1995 (as restated) | 1,511 | 379 | 1,890 | 26.9 | 24.7 | 51.6 | 280.0 | – | 280.0 | 1.7 | 2.5 | 4.2 |
| Discoveries and Extensions | 251 | 207 | 458 | 17.8 | 1.1 | 18.9 | – | 490.0 | 490.0 | 0.4 | (0.7) | (0.3) |
| Acquisition of Reserves – Net | 615 | 285 | 900 | 33.2 | 15.0 | 48.2 | – | – | – | – | – | – |
| Production | (188) | – | (188) | (8.9) | – | (8.9) | (11.0) | – | (11.0) | (0.6) | – | (0.6) |
| Balance at December 31, 1996 | 2,189 | 871 | 3,060 | 69.0 | 40.8 | 109.8 | 269.0 | 490.0 | 759.0 | 1.5 | 1.8 | 3.3 |
| **1997** | | | | | | | | | | | | |
| Revisions of Established Pools | 72 | (30) | 42 | 2.0 | (0.9) | 1.1 | – | – | – | – | – | – |
| Discoveries and Extensions | 571 | 280 | 851 | 22.0 | 3.2 | 25.2 | 122.4 | (143.3) | (20.9) | 1.3 | 0.3 | 1.6 |
| Acquisition of Reserves – Net | (33) | (21) | (54) | (5.8) | (2.4) | (8.2) | – | – | – | – | – | – |
| Production | (214) | – | (214) | (10.4) | – | (10.4) | (10.3) | – | (10.3) | (0.7) | – | (0.7) |
| Balance at December 31, 1997 | 2,585 | 1,100 | 3,685 | 76.8 | 40.7 | 117.5 | 381.1 | 346.7 | 727.8 | 2.1 | 2.1 | 4.2 |
| **1998** | | | | | | | | | | | | |
| Revisions of Established Pools | (66) | 4 | (62) | 4.9 | (4.5) | 0.4 | (6.8) | – | (6.8) | (0.2) | (0.3) | (0.5) |
| Discoveries and Extensions | 481 | 175 | 656 | 31.4 | 7.7 | 39.1 | 0.3 | 7.8 | 8.1 | 2.4 | – | 2.4 |
| Acquisition of Reserves – Net | 145 | 42 | 187 | 68.8 | 66.0 | 134.8 | – | – | – | – | – | – |
| Production | (259) | – | (259) | (10.5) | – | (10.5) | (10.6) | – | (10.6) | (0.9) | – | (0.9) |
| Balance at December 31, 1998 | 2,886 | 1,321 | 4,207 | 171.4 | 109.9 | 281.3 | 364.0 | 354.5 | 718.5 | 3.4 | 1.8 | 5.2 |

*Note 1: Year-end conventional reserves balances have been independently estimated by consulting engineers McDaniel & Associates Consultants Ltd. and Gilbert Laustsen Jung Associates Ltd.*

**LANDHOLDINGS AT YEAR-END 1998**
**(thousand acres)**

| | Western Canada Developed | Undeveloped | Other North American Developed | Undeveloped | Total North America Developed | Undeveloped | International Developed | Undeveloped | Total Undeveloped |
|---|---|---|---|---|---|---|---|---|---|
| Gross | 2,292 | 7,898 | 0.5 | 510 | 2,292 | 8,408 | 29 | 4,268 | 12,676 |
| Net | 1,727 | 6,810 | 0.5 | 280 | 1,727 | 7,090 | 29 | 1,751 | 8,841 |

**WELLS DRILLED (WESTERN CANADA)**

| | 1998 Gross | Net | 1997 Gross | Net | 1996 Gross | Net |
|---|---|---|---|---|---|---|
| Exploration | | | | | | |
| Gas | 152 | 131 | 82 | 76 | 68 | 65 |
| Oil | 27 | 24 | 20 | 17 | 22 | 19 |
| Cased | 3 | 3 | 8 | 7 | 11 | 11 |
| Dry and Abandoned | 25 | 21 | 35 | 33 | 42 | 40 |
| Total | 207 | 179 | 145 | 133 | 143 | 135 |
| Success Rate (percent) | 88 | 88 | 76 | 75 | 71 | 70 |
| Development | | | | | | |
| Gas | 377 | 356 | 160 | 133 | 103 | 86 |
| Oil | 39 | 31 | 127 | 88 | 172 | 135 |
| Cased | 7 | 6 | 27 | 26 | 14 | 13 |
| Dry and Abandoned | 5 | 2 | 18 | 11 | 27 | 24 |
| Total | 428 | 395 | 332 | 258 | 316 | 258 |
| Success Rate (percent) | 99 | 99 | 95 | 96 | 91 | 91 |

# Supplemental Information (Unaudited)

**Alberta Energy Company Ltd.**

**OIL AND GAS OPERATING STATISTICS**

| | 1998 | 1997 | 1996 | 1995 | 1994 |
|---|---|---|---|---|---|
| **Undeveloped Acreage (thousand acres)** | | | | | |
| North America | | | | | |
| Gross | 8,408 | 7,335 | 5,180 | 3,240 | 2,017 |
| Net | 7,090 | 6,263 | 4,279 | 2,667 | 1,731 |
| International | | | | | |
| Gross | 4,268 | 2,945 | 2,921 | 452 | 372 |
| Net | 1,751 | 2,945 | 2,711 | 452 | 372 |

| | 1998 | 1997 | 1996 | 1995 | 1994 |
|---|---|---|---|---|---|
| **Reserves (before royalties)** | | | | | |
| Gas (billion cubic feet) | | | | | |
| Proven | 2,886 | 2,585 | 2,189 | 1,511 | 1,522 |
| Probable | 1,321 | 1,100 | 871 | 379 | 369 |
| Total | 4,207 | 3,685 | 3,060 | 1,890 | 1,891 |
| Conventional Oil and Natural Gas Liquids (million barrels) | | | | | |
| Proven | 171.4 | 76.8 | 69.0 | 26.9 | 26.0 |
| Probable | 109.9 | 40.7 | 40.8 | 24.7 | 14.8 |
| Total | 281.3 | 117.5 | 109.8 | 51.6 | 40.8 |
| Syncrude (million barrels) | 718.5 | 727.8 | 759.0 | 280.0 | 269.0 |
| Argentina Oil (million barrels) | 5.2 | 4.2 | 3.3 | 4.2 | 4.2 |

| | 1998 | 1997 | 1996 | 1995 | 1994 |
|---|---|---|---|---|---|
| **Reserves Replacement Cost Calculation** | | | | | |
| Proven and Probable (Western Canada) | | | | | |
| Conventional Oil and Gas Investment ($ millions) | | | | | |
| Exploration | 161.0 | 318.0 | 168.2 | 82.7 | 66.1 |
| Development | 429.6 | 343.6 | 256.5 | 100.0 | 105.0 |
| Acquisitions | 795.7 | 7.8 | 975.5 | 9.4 | 66.3 |
| Total Reserves Replacement Costs | 1,386.3 | 669.4 | 1,400.2 | 192.1 | 237.4 |
| Proven Plus Probable Reserves Added | | | | | |
| Gas (billion cubic feet) | | | | | |
| Discoveries and Extensions | 656.2 | 851.0 | 458.0 | 138.4 | 94.1 |
| Revisions | (62.6) | 41.9 | – | (49.3) | 14.0 |
| Acquisitions | 187.0 | – | 900.0 | 38.2 | 140.9 |
| Total | 780.6 | 892.9 | 1,358.0 | 127.3 | 249.0 |
| Conventional Oil and Natural Gas Liquids (million barrels) | | | | | |
| Discoveries and Extensions | 39.1 | 25.2 | 18.9 | 24.1 | 12.6 |
| Revisions | 0.4 | 0.7 | – | (7.9) | 6.0 |
| Acquisitions | 134.8 | – | 48.2 | – | 0.1 |
| Total | 174.3 | 25.9 | 67.1 | 16.2 | 18.7 |
| Total Reserve Additions 10:1 (barrel of oil equivalent) | 252.4 | 115.2 | 202.9 | 28.9 | 43.6 |
| Reserves Replacement Costs ($/barrel of oil equivalent) | | | | | |
| 10:1 | 5.49 | 5.81 | 6.90 | 6.64 | 5.44 |
| 6:1 | 4.55 | 3.83 | 4.77 | 5.13 | 3.94 |

# Corporate Information

**BOARD OF DIRECTORS**

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*Embee Consulting Ltd.*
*Edmonton, Alberta*

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*Chairman of the Board*
*TransCanada PipeLines Limited*
*Calgary, Alberta*

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*Private Investor*
*Calgary, Alberta*

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*Chairman &*
*Chief Executive Officer*
*Jascan Resources Inc.*
*Toronto, Ontario*

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*D.A. Lucas Enterprises Inc.*
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*McCarthy Tétrault*
*Barristers and Solicitors*
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*Alberta Energy Company Ltd.*
*Calgary, Alberta*

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*President &*
*Chief Executive Officer*
*Alberta Energy Company Ltd.*
*Calgary, Alberta*

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*Corporate Director*
*Calgary, Alberta*

**T. DON STACY** [1,2]
*Corporate Director*
*Houston, Texas*

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*President & Chief Executive Officer*

**DRUDE RIMELL**
*Vice-President, Corporate Services*

**Wayne G. Holt**
*General Counsel*

**Donald E. Smallwood**
*Director,*
*Human Resource Services*

**Hayward J. Walls**
*Director, Information Technology Services*

**JOHN D. WATSON**
*Vice-President, Finance &*
*Chief Financial Officer*

**Ronald H. Westcott**
*Comptroller*
*(Vice-President, Finance – AEC Oil & Gas Partnership)*

**Kenneth S. Aberle**
*Director, Tax & Treasury Operations*
*& Assistant Treasurer*

**Derek S. Bwint**
*Director, Corporate Risk*

**Bernard K. Lee**
*Director, Corporate Finance*
*& Assistant Treasurer*

**BRIAN C. FERGUSON**
*Director, Corporate Relations*
*& Corporate Secretary*

**Linda H. Mackid**
*Assistant Corporate Secretary*

**Richard H. Wilson**
*Director, Public Affairs*

**COMMITTEES OF THE BOARD**

1 *Audit Committee*
2 *Environment, Health & Safety Committee*
3 *Human Resources & Compensation Committee*
4 *Nominating & Corporate Governance Committee*
5 *Pension Committee*

**BUSINESS UNIT LEADERS**

**UPSTREAM**

**AEC MARKETING**
**BILL OLIVER**
*Vice-President – AEC*
*(Executive Vice-President, AEC Marketing)*

**AEC EAST**
**RANDALL K. ERESMAN**
*Vice-President – AEC*
*(Senior Vice-President, AEC East)*

**Roger J. Biemans**
*Vice-President*

**Robert A. Grant**
*Vice-President*

**AEC WEST**
**KENNETH J. WOLDUM**
*Senior Vice-President,*
*AEC West*

**Guy C.L. James**
*Vice-President*

**Keith R. Kirkness**
*Vice-President*

**AEC INTERNATIONAL**
**STEVEN R. BELL**
*Vice-President – AEC*
*(Executive Vice-President, AEC International)*

**Gary S. Guidry**
*Vice-President,*
*Operations & Engineering*

**Brian J. Moss**
*Vice-President*

**AEC SYNCRUDE**
**Roger D. Dunn**
*Chairman, Syncrude Management Committee*

**BUSINESS UNIT LEADERS**

**MIDSTREAM**

**HECTOR J. MCFADYEN**
*Vice-President – AEC*
*(President, AEC Midstream)*

**J. Andrew Patterson**
*Vice-President, Finance*
*AEC Midstream*

**PIPELINES & GAS PROCESSING**

**Robert A. Towler**
*Senior Vice-President,*
*Business Development*

**Larry D. Drader**
*Vice-President,*
*Operations & Engineering*

**Bernie J. Bradley**
*President, Express Pipeline System*

**AEC STORAGE AND HUB SERVICES**

**Richard C. Daniel**
*Vice-President*

# Corporate Information

**AEC REGISTERED/ HEAD OFFICE**
*3900, 421 - 7 Avenue S.W.*
*Calgary, Alberta T2P 4K9*
*Phone: (403) 266-8111*
*Internet Address*
*www.aec.ca*

**TRANSFER AGENTS & REGISTRARS**
*Common Shares*
**CIBC Mellon Trust Company**
*Calgary, Vancouver, Regina, Winnipeg, Toronto, Montreal, Halifax, and*
**Chasemellon Shareholder Services, L.L.C.**
*New York*

**TRUSTEE & REGISTRAR**
**CIBC Mellon Trust Company**
*8.15% Debentures*
*Calgary, Vancouver, Regina, Winnipeg, Toronto, Montreal, Halifax*
*Medium Term Note Debentures*
*Calgary, Toronto*

*Investors are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached via the AnswerLine (416) 643-5500 or toll-free throughout North America at 1-800-387-0825.*

**Mailing Address**
*CIBC Mellon Trust Company*
*600 Dome Tower*
*333 - 7 Avenue S.W.*
*Calgary, Alberta T2P 2Z1*
*Internet Addresses*
*inquiries@cibcmellon.ca (e-mail)*
*www.cibcmellon.ca (web site)*

**AUDITORS (FINANCIAL)**
**PricewaterhouseCoopers LLP**
**Chartered Accountants**
*Calgary, Alberta*

**AUDITORS (CONVENTIONAL OIL & GAS RESERVES)**
**McDaniel & Associates Consultants Ltd.**
*Calgary, Alberta*
**Gilbert Laustsen Jung Associates Ltd.**
*Calgary, Alberta*

**STOCK EXCHANGES**
*Common Shares are listed on the Toronto and Montreal stock exchanges (symbol "AEC") and on the New York Stock Exchange (symbol "AOG").*

**ANNUAL INFORMATION FORM (FORM 40-F)**
*AEC's Annual Information Form (AIF) is filed with securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System (MJDS), AEC's AIF is filed as Form 40-F with the U.S. Securities and Exchange Commission.*

**DIVIDEND REINVESTMENT & SHARE PURCHASE PLAN**
*AEC offers a Dividend Reinvestment and Share Purchase Plan which provides a convenient method for share-holders to reinvest their cash dividends and/or make cash investments to purchase additional Common Shares. Details may be obtained by contacting CIBC Mellon Trust Company at the AnswerLine phone numbers on this page.*

**MAJOR OPERATING SUBSIDIARIES, AFFILIATES & PARTNERSHIPS**

**Upstream**
*100% AEC International (Australia) Pty Ltd*
*100% AEC Oil & Gas Partnership*
*100% AEC Oil Sands Ltd.*
*100% AEC Oil Sands, L.P.*
*100% AEC West Ltd.*
*100% Alberta Energy Company Argentina S.A.*
*100% Alenco Inc.*
*100% Alenco Oil & Gas [N.D.] Inc.*
*100% Alenco Resources Inc.*
*100% AEC Marketing (USA) Inc.*
*100% Amber Energy Inc.*

**Midstream**
*100% AEC Express Holdings Ltd.*
*100% AEC Pipelines Ltd.*
*70% AEC Pipelines, L.P.*
*100% AEC Suffield Gas Pipeline Inc.*
*50% Express Pipeline*
*50% Platte Pipe Line Company*
*50% Marquest Energy Group*
*100% Alenco Pipelines Inc.*
*100% Alenco Iroquois Pipelines Inc.*
*6% Iroquois Gas Transmission System, L.P.*
*100% Wild Goose Storage Inc.*
*100% AEC Storage and Hub Services Inc.*

**MAJOR JOINT VENTURES**

**Upstream**
*13.75% Syncrude (AEC Oil Sands, L.P.) (includes 75% of AEC Oil Sands Limited Partnership's 5% interest)*

**Midstream**
*35% Empress Straddle Plant*
*33.3% Alberta Ethane Gathering System*

**ADDITIONAL INFORMATION**
*For additional investor relations information please contact Brian C. Ferguson, Director, Corporate Relations & Corporate Secretary, at the Registered Office address:*
*3900, 421 - 7 Avenue S.W.*
*Calgary, Alberta T2P 4K9*
*Phone: (403) 266-8111*
*Internet Address*
*www.aec.ca*

**ANNUAL MEETING OF SHAREHOLDERS**
*Wednesday, April 21, 1999*
*at 3:00 p.m. local time*
*TELUS Convention Centre*
*120 - 9 Avenue S.E.*
*Calgary, Alberta*
*Shareholders of Alberta Energy Company Ltd. are encouraged to attend. Those unable to do so are asked to sign and return the form of proxy mailed with this report.*

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Alberta Energy Company Ltd.

AEC